CHAPTER 4 FUGITIVES MONITORING

This chapter addresses the EPA's responses to public comments on fugitive emissions monitoring in the EPA's Proposed *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources*.

Commenters also raised issues on topics that are not covered by this chapter. Please refer to the following chapters for responses specific to those issues:

- **Chapter 1**: Source Category
- **Chapter 2**: Regulation of Methane
- **Chapter 3**: Well Completions
- **Chapter 5**: Pumps
- **Chapter 6**: Controllers
- **Chapter 7**: Compressors
- **Chapter 8**: Equipment Leaks at Natural Gas Processing Plants
- **Chapter 9**: Liquids Unloading
- **Chapter 10**: Storage Vessels
- **Chapter 11**: Compliance
- **Chapter 12**: Regulatory Impact Analysis
- **Chapter 13**: Existing State, Local, and Federal Rules
- **Chapter 14**: Subpart OOOO
- **Chapter 15**: Miscellaneous
- **Chapter 16**: Comment Period Extension

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4.1 General Support for Proposed Standards

Commenter Name: Haley Colson Lewis, Programs Manager and Michael Hansen, Interim Executive Director
Commenter Affiliation: GASP
Document Control Number: EPA-HQ-OAR-2010-0505-6436;
Comment Excerpt Number: 6

Comment: GASP also supports the proposal to conduct fugitive emissions surveys semiannually with optical gas imaging technology and to repair the sources of such fugitive emissions within 15 days that are found during those surveys. These semiannual surveys and a requirement to repair the sources of fugitive emissions within 15 days will ensure that newly constructed oil and gas wells will not be like some of the existing "super emitters."

Response: The EPA thanks the commenters for their support for the proposed standards for fugitive emissions from well sites and compressor stations. We have finalized the standards to require semiannual monitoring using OGI or Method 21 at well sites and quarterly monitoring using OGI or Method 21 at compressor stations. However, we have revised the repair requirement to allow facilities 30 days to repair fugitive emission leaks during the OGI or Method 21 survey (See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8).

Commenter Name: Henri Azibert, Technical Director
Commenter Affiliation: Fluid Sealing Association (FSA)
Document Control Number: EPA-HQ-OAR-2010-0505-6754
Comment Excerpt Number: 6

Comment: Leak, Detect, and Repair (LDAR) programs have been in use for quite some time now, in petroleum products refining and chemical processing, and have proven to be extremely effective to reduce emission levels. Reasonably achievable emissions levels are different for different types of equipment. We do agree that the BSER (Best System of Emissions Reductions) is the same for methane as it is for VOCs, (Volatile Organic Compounds.) Leak detection and repair is a critical component to reducing methane and VOC emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6. With respect to BSER for methane and VOC, we agree with the commenter that there are cost-effective controls that can simultaneously reduce both methane and VOC emissions from equipment across the industry.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 9

Comment: There are reports of numerous technologies made by U.S. businesses that are helping oil and gas companies to find and fix methane leaks. As reported recently (http://www.environmental-expert.com/news/the-us-oil-and-natural-gas-producers-want-to-be-part-of-the-climatesolution-622309), “the American Petroleum Institute is looking to be part of the solution rather than simply named as the problem. The US oil and natural gas producers have had positive impacts to the US economy while helping to achieve substantial emissions reductions.” Thus, the technologies are available and some industry is willing and already creating positive impacts. These regulatory changes will create an even playing field for both industry and the public’s health and safety. Common-sense regulations that make best practices the standard practice can help the U.S. reach its methane reduction goal.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 10

Comment: We recommend the proposal that new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) conduct fugitive emissions surveys semiannually with optical gas imaging (OGI) technology and repair the sources of fugitive emissions within 15 days that are found during those surveys. We recommend that any surveys that indicate an immediate public health and safety risk be immediately repaired.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 22

Comment: We recommend the proposal for standards to reduce fugitive methane and VOC emissions from new and modified natural gas compressor stations throughout the oil and natural gas source category.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6.

Commenter Name: Michael J. Meyers, et al., Assistant Attorneys General
Commenter Affiliation: Attorneys Generals of New York, Massachusetts, Oregon, Rhode Island, and Vermont (States)
Document Control Number: EPA-HQ-OAR-2010-0505-6940
Comment Excerpt Number: 11

Comment: EPA reasonably determined that fugitive methane emissions from well sites and compressor stations and equipment leaks at natural gas processing plants can be cost-effectively reduced.

EPA has reasonably proposed to require leak detection surveys at well sites and compressor stations to address fugitive methane emissions. EPA's "Oil and Natural Gas Sector Leaks" white paper acknowledges that as the oil and natural gas exploration and production industry in the U.S. grows rapidly, so does the potential for greater methane emissions from leaks. As EPA notes, "leak emissions occur through many types of connection points (e.g., flanges, seals, threaded fittings) or through moving parts of valves, pumps, compressors, and other types of process equipment." EPA OAQPS, Oil and Natural Gas Sector Leaks 3 (2014) [hereinafter Oil and Natural Gas Sector Leaks White Paper]. The white paper identifies a number of different leak detection technologies, including portable analyzers and optical gas imaging (OGI) technology using infrared cameras, which are readily available and inexpensive. As discussed in the report by Carbon Limits, Quantifying Cost-effectiveness of Systematic Leak Detection and

Repair Programs Using Infrared Cameras 6 (2014), infrared cameras can be used relatively inexpensively to scan an entire facility for leaks. Furthermore, EPA has determined that "once a leak is found it is almost always economical to repair the leak" and that directed inspection and maintenance programs "can effectively decrease leak emissions." Oil and Natural Gas Sector Leaks White Paper at 55. In light of these findings that fugitive emission surveys using OGI and leak detection and repair programs can effectively reduce methane emissions from leaks at a reasonable cost, EPA has reasonably proposed to follow the lead of states such as Colorado that have made these programs mandatory.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 85

Comment: We applaud the EPA's work and proposed regulation to cover not only emissions from production of processing of oil and gas, but also to emissions from transmission and storage and to require owners and operators to find and fix leaks.

The EESI is also pleased to see that EPA expanded its new sources rules to cover sources previously unregulated in the 2012 ESE air rules, such as future emissions from well sites, compressor stations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 42

Comment: I also encourage the U.S. EPA to conduct a regular monitoring program to ensure these regulations are followed. It is disconcerting that the gas industry recklessly allows release of methane and other volatile carcinogen—carcinogenic and endocrine destructive organic compounds to be released indiscriminately into the surrounding environment. Our health and the health of our children should not be sacrificed in order for the oil and gas industry to maintain profits.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Numbers: 115, 116

Comment: The leak detection and repair program have been in use for quite some time now in the petroleum and product refining and chemical processing and have proven to be certainly effective to reduce emission levels. Reasonably achievable emission levels are different for different types of equipment. We do agree that the best system of emission reduction is the same for methane as it is for VOCs, or volatile organic compounds. Leak detection and repairs are critical components to reducing methane and VOC emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 9

Comment: With respect to these proposed rules, specifically, we support an aggressive leak detection survey moderated with appropriate communications in a timely fashion. We would also support incentives built into the rule that would encourage operators and owners to use the best technology available to form a leak detection in—data suggests that methane leakage is a bigger magnitude than originally thought. Since natural gas is considered by many experts serves as a bridge fuel for reducing carbon dioxide emissions, an aggressive leak reduction program is necessary to enjoy an overall emission reduction.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6.

Commenter Name: Roy Rusty Bennett
Commenter Affiliation: Mehoopany Creek Watershed
Document Control Number: EPA-HQ-OAR-2010-0505-6816
Comment Excerpt Number: 10

Comment: We are concerned about fugitive emissions at natural gas production well sites. There are over 100 wells within our 134.5 square mile watershed on multi-well sites. All of the producing well sites have one dehydrator per well and at least two tanks on each site. In some cases a well site may have compressor engines. Because of PA DEP's Exemption 38 all of this equipment is exempt. We are very concerned about this as sites tend to be spaced only 2-3,000 feet and our homes and school are all within the environs. Three well pads are within 2,700 feet of our school. Thus we are experiencing an increasing load of harmful VOCs and HAPs near our homes and school.

We are concerned about VOCs and HAPs emitted from compressor stations. We are concerned about uncontrolled releases and fugitive emissions. Our school is just over a mile from the nearest compressor station and proposed LNG plant. There are five compressor stations, a proposed LNG plant and a proposed 20 MW natural gas power plant all within five miles of our school. All of these facilities emit or will emit harmful VOC's including formaldehyde and HAPs.

We recommend the proposal for standards to reduce fugitive methane and VOC emissions from new and modified natural gas compressor stations throughout the oil and natural gas source category.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6436, Excerpt 6.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 28

Comment: Equipment leaks are the largest source of emissions from the oil and gas sector and readily available solutions exist to address this pollution.

Equipment Leaks are a Significant Source of Emissions. Leaked emissions of methane and VOCs from the oil and gas industry are significant. According to the 2013 GHG Inventory, fugitive emissions account for 35% of emissions from the natural gas and upstream petroleum sectors. ICF has found that leaks are the largest emissions category in the oil and gas industry, estimating that emissions from these sources will account for nearly 2.3 million metric tons of methane in 2018, or 30% of all emissions from the oil and gas sector.

Moreover, recent scientific research, such as the Barnett Shale Field Campaign, University of Texas' Allen Studies, Gathering and Processing Study, and the Transmission and Storage Study —conducted across various geographies and value chain segments, and with diverse methodologies— confirms that leaks are a significant source and suggests that current inventories likely underestimate their magnitude.

Response: The EPA thanks the commenters for the information provided. We have reviewed the studies provided by the commenter and believe that our methodology outlined in the TSD for the final rule provides the best estimate of fugitive emissions from well sites and compressor stations.

4.2 General Opposition to Proposed Standards

Commenter Name: W. Michael Scott, General Counsel
Commenter Affiliation: Trilogy Operating, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6603
Comment Excerpt Number: 28

Comment: The new controls required under Subpart OOOO and the Methane NSPS already address the primary sources of methane emissions from equipment in the oil and gas sector. Given the anticipated volume of reductions that will be achieved by the new control rules, the fugitive emission monitoring surveys are unnecessary. As previously noted, the fugitive emissions from the well sites and compressor sites are a relatively small portion of the total domestic greenhouse gas emissions. The small leaks that these Rules would require operators to monitor and repair make up an even more minuscule percentage of the emissions from those sites, and do not warrant the amount of resources that would have to be devoted to constantly checking and repairing possible leaks.

Response: The EPA disagrees with the commenter's assertion that regulation of fugitive emissions for well sites and compressor stations is not justified. As shown in Table 9-3 of the TSD for the final rule, semiannual OGI monitoring and repair at well sites would achieve 152,656 tons per year methane reductions and 41,880 tons per year of VOC in 2020 at an annual cost of $2,285 per well site. We believe that this is a significant reduction of both methane and VOC at a relatively low annual cost.

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 26

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 25

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 26

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 26

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 27

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 26

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 58

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 9

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 7

Commenter Name/Affiliation: Denzil R. West / Reliance Energy, Inc.
Document Control/ Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 9

Commenter Name/Affiliation: Brandon M. Black / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 9

Commenter Name/Affiliation: Joe Strickling / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 9

Comment: The fugitive emission surveys are impractical and unnecessary for facilities that have instituted the emission controls required under Subpart OOOO or OOOOa, and the definition of "fugitive emissions component" is too vague.

The new controls required under Subpart OOOO and the Methane NSPS already address the primary sources of methane emissions from equipment in the oil and gas sector. Given the anticipated volume of reductions that will be achieved by the new control rules, the fugitive emission monitoring surveys are unnecessary.

Response: The EPA disagrees that fugitive emissions surveys are impractical and unnecessary. While the control requirements of the final rule will help to reduce emissions of VOC and methane, fugitive emissions are a significant emission source. See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 28. Additionally, the data available to the EPA regarding compressor stations indicates that they can be a significant source of fugitive methane emissions. Therefore, we have included requirements for fugitive monitoring consistent with the BSER analysis. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

We agree with the commenters that as proposed, the fugitive emissions component definition may cause confusion due to inclusion of equipment types, such as uncontrolled storage vessels that are potential sources of vented emissions (as opposed to fugitive emissions), in the definition. Therefore, we are finalizing changes to the definition to remove equipment types and identify specific components, such as valves and flanges that have the potential to be sources of fugitive emissions. See sections VI.F.1.f and VI.F.2.e of the final rule preamble for more information.

Commenter Name: Steve Henke
Commenter Affiliation: New Mexico Oil and Gas Association (NMOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6850
Comment Excerpt Number: 5

Comment: EPA should withdraw the LDAR monitoring requirements from the proposed NSPS OOOOa. Managing fugitive emissions at oil and natural gas production operations is an emerging process. First, the currently proposed method will require component counts at affected facilities. The process to capture accurate component counts at a wide range of sites spread across large geographic regions will require extensive resources and cost, while providing very little benefit in terms of emissions reduction. Furthermore, recent data demonstrate that production fugitive emissions are characterized by a few sources ("fat tails") representing the overwhelming majority of emissions. EPA should withdraw the proposed LDAR NSPS because it has not been developed based on the emerging experiences with fugitive emissions management programs in the states which currently have LDAR requirements. Furthermore, it locks in a technology approach that may be cost ineffective as experience with state programs evolves, and it would stifle the development of better approaches. Instead, EPA should work with states to learn from their programs and provide for a flexible voluntary fugitive emissions program in the Methane Challenge that would build a basis for a cost effective NSPS in the future if one is needed.

Response: We disagree with the commenter's recommendation that LDAR monitoring be withdrawn from the final rule. We are not finalizing performance based monitoring; therefore, the percentage of leaking components which would require component counts, will not be needed to determine monitoring frequency. The final rule allows the use of OGI, as well as Method 21 approved devices. Additionally, see response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

We have also provided flexibility for repair of leaking components to allow additional time for repairs that cannot be made during the survey. We believe the monitoring requirements will not only find "fat tails", but also find other significant leaks that may not be discovered during periodic audio, visual, or olfactory (AVO) inspections. In addition, we believe periodic monitoring will reduce the number of "fat tails" by finding these leaks before they become significant leakers. There have been several studies that have shown that fugitive emission have decreased over the last couple of years, however many of these reductions have come as a result of voluntary programs or state regulations. To achieve significant reductions in methane and VOC, we believe national fugitive monitoring requirements are warranted. We believe the fugitive monitoring requirements in the final rule provide a cost effective approach to reducing fugitive emissions from well sites and compressor stations. See section VI.F.1.c of the final rule preamble for more information.

Commenter Name: Tom Michels
Commenter Affiliation: ONE Future

Document Control Number: EPA-HQ-OAR-2010-0505-6880
Comment Excerpt Number: 6

Comment: The proposed OOOOa requirements to address fugitive emissions have numerous deficiencies. The Proposed Rule does not provide an endpoint or off-ramp from mandatory monitoring, nor does it incorporate any existing alternative LDAR programs. At a given site, *any* LDAR program will become less cost-effective over time, as leaks are repaired and production declines. The costs associated with the OOOOa-prescribed LDAR, however, are ongoing, creating unnecessary, ineffective spending that would reduce the ability to apply scarce funds to more meaningful emission detection and reduction projects – which is central to ONE Future's performance-based design.

The Proposed Rule sets forth a prescriptive LDAR program, including initial instrument survey, semiannual surveys, leaking component/equipment repair deadlines (irrespective of the significance of the leak), and significant recordkeeping and reporting elements. Although this proposal establishes a baseline road map for those implementing a LDAR program for the first time, it penalizes those operators that have been implementing alternative measures for addressing fugitives on a voluntary basis. In addition, the prescriptive nature of the proposed work practice standards do not allow companies to identify or pursue improvements to the rule that may be known now or may become clear over time, such as a different frequency of surveys, alternative instrumentation used in the surveys, or application of future continuous emissions detection system. (Moving to a more data-drive, risk-based approach over time is at the heart of the Directed and Inspection Maintenance Program concept.) Delineating such a prescriptive LDAR program prevents companies from implementing efficiency measures that lower the actual cost of the fugitive emissions control measures – and may often prevent capital expenditure on measures that would prevent future leaks.

Depending on a company's assets and geographic footprint, the inspection and repair schedule that would be imposed by the Proposed Rule on new and modified sources may be draconian, and will divert resources away from more effective efforts to find and fix fugitive emissions elsewhere in their existing assets. Many companies achieve greater cost-efficiency by coordinating Fugitive Emission surveys based on well site and compressor station locations, which significantly reduces travel time and costs, while yielding superior systemic results and awareness. However, as proposed, many companies are confronting the very real prospect that the resources which they would otherwise have dedicated to area-wide fugitive emission reductions will be principally consumed by OOOOa compliance.

Response: Fugitive emissions components will continue to leak and need to be repaired even as production declines. The supporting calculations in the TSD are based on emission factors that are not dependent on production, and therefore the cost per ton calculations are the same for low production well sites. See the Chapter 4 of the TSD for the final rule for more information. Also see response to DCN EPA-HQ-OAR-2010-0505-6850, Excerpt 5, response DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7, for information regarding directed inspection and maintenance programs and final rule preamble sections VI.F.2.d and VI.F.2.g.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 14

Comment: The proposed LDAR program is highly problematic in numerous respects and would be extremely difficult and costly to implement; all while providing little emissions benefit over and above state and voluntary operator programs. There are proven feasible and cost-effective alternatives to EPA's proposed LDAR program. These alternatives are flexible, cost-effective, and provide the same (or improved) benefits to the environment. Such alternatives include corporate-wide programs executed voluntarily and compliance with various state-mandated regulatory programs (such as in Wyoming and Colorado). Other programs—such as those modeled after D&IM programs—allow operators to focus on high and frequent emitters. Our members have extensive experience implementing voluntary programs, and we look forward to working with EPA and partnering with state regulators to apply this knowledge and experience.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 28. Additionally, we note that we have added a procedure at §60.5398a of the final rule for owners or operators of affected facilities to apply to the Administrator for a determination of whether an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §60.5397a. Such an alternate means may include corporate fugitive emissions monitoring programs that deviate from the requirements of §60.5397a. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 6

Comment: Second, within the NSPS proposal, the most egregious element is the proposed fugitive emissions regulations that are based on purely speculative emissions reductions but, as designed, are excessively and unnecessarily burdensome. Oil and natural gas production fugitive emissions management is an emerging arena with companies and state regulatory programs still learning how best to efficiently and effectively control them. Several states are currently implementing programs; none of which parallel EPA's proposals. Experience with those state efforts demonstrates that emissions patterns result from a few high emissions sources that can be managed quickly with sustained reductions. EPA's proposal to lock in an unworkable program for at least 5 years is arbitrary and inappropriate. EPA should await the analysis of state programs to determine whether an NSPS is logical or necessary.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6850, Excerpt 5.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 8

Comment: Comments to the Proposed NSPS for Methane, Subpart OOOOa: Fugitive Emissions at Well Sites and Compressor Stations

Pioneer's largest area of concern from the proposed methane NSPS are the fugitive emissions LDAR requirements at well sites and compressor stations. Therefore, the remainder of our comments for this specific rule will pertain to this requirement. As an initial point, the majority of Pioneer's natural gas is composed of methane, a saleable product, and emissions reduction measures target all pollutants in the gas stream, including methane. Industry has a huge economic incentive to capture emissions and route them to the sales line. The business objectives and economic goals truly align on this issue. Many companies are already employing plans and actions to voluntarily reduce their emissions to be good stewards of the environment, meet the expectations of their investors, shareholders and the public, and as a business objective to capture and sell gas that may otherwise be flared or vented to the atmosphere. Pioneer also supports the concept of a voluntary program, such as the concept of EPA's recently introduced methane challenge that allows companies to further reduce emissions where it is most beneficial and cost-effective based on their operations, and to tailor a program for each unique operating area.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6850, Excerpt 5.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 20

Comment: Delay finalizing an LDAR until more information is gathered from operator and state programs

Although Pioneer suggested the above changes to the LDAR proposal, a preferred overarching alternative, as articulated in IPAA/AXPC's comments would be for EPA to withdraw the proposed LDAR NSPS because it has not been developed based on the emerging experiences with fugitive emissions management programs, it locks in a technology approach that may be cost ineffective as experience with state programs evolves, and it would stifle the development of better approaches. Instead, EPA should work with states to learn from their programs and provide for a flexible voluntary fugitive emissions program in the Methane Challenge that would build a basis for a cost-effective NSPS in the future, if one is needed. At a minimum, implementation of any program should be delayed and EPA should work with industry to establish the necessary elements of a corporate fugitive monitoring plan that companies could adopt and customize to meet their particular needs while satisfying EPA's LDAR requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6850, Excerpt 5.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 10

Comment: Operator's existing leak detection plans should be accepted.

Response: We disagree with the commenter that existing operator's plans should be accepted, without knowing the stringency of the existing leak detection plan. The final rule requires semiannual monitoring of well sites using either OGI or Method 21 along with the development and implementation of a monitoring plan.

Commenter Name: Mark A. Litwin
Commenter Affiliation: Paiute Pipeline Company
Document Control Number: EPA-HQ-OAR-2010-0505-6814
Comment Excerpt Number: 4

Comment: As discussed in the AG's submittal, Paiute also believes that the proposed leak detection and repair (LDAR) program is cumbersome and impractical, and that the proposed fugitive emissions program should only apply to new or upgraded compressors that meet the current definitions of a "modification".

Response: We disagree with the commenter that modification at a compressor station should only apply to new or upgraded compressors. We believe that the addition of a compressor, either new or used, should also constitute a modification at a compressor station. In addition, we have added clarifications for upgrading existing compressors. Please see preamble to the final rule section VI.F.2.h. for further discussion.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 8

Comment: Proposed Standards for Fugitive Emissions from Well Sites

Hess generally supports the use of new technologies to find and fix leaks of hydrocarbons and other emissions from crude oil and natural gas production operations equipment. As pointed out by EPA, the oil and gas industry has a financial incentive to reduce losses from leaky equipment. Likewise, Hess and other operators also have a responsibility to be good stewards of shareholder money. Accordingly, Hess supports a find and fix program that will be effective and protective of human health and the environment, but which does not include significant and expensive administrative burdens, excessive recordkeeping, or unnecessarily frequent inspections that are unlikely to discover new leaks.

Response: We agree with the commenter that companies have both a financial incentive and responsibility to reduce fugitive emissions. However, we disagree with the commenter that the proposed rule includes significant administrative burdens, excessive recordkeeping, or unnecessary inspections. We have reviewed both the recordkeeping and administrative burdens and believe that they are appropriate to show compliance with the fugitive regulations. In addition, we believe that the semiannual monitoring program requirement provides significant emission reductions of both methane and VOC. Please see Volume 1 of the Technical Support Document (section 4).

4.3 Best System of Emission Reduction

Commenter Name/Affiliation: Kari Cutting / North Dakota Petroleum Council (NDPC)
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6789 / Excerpt Number: 17

Commenter Name/Affiliation: J. Roger Kelley / Domestic Energy Producer's Alliance (DEPA)
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6793 / Excerpt Number: 14

Commenter Name/Affiliation: J. Roger Kelley / Domestic Energy Producer's Alliance (DEPA)
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6793 / Excerpt Number: 15

Comment: EPA's proposed best system of emissions reduction ("BSER") for fugitive emissions, optical gas imaging ("OGI"), is not a feasible or practicable standard under the CAA. EPA has not adequately considered the technological and human resource limitations associated with addressing fugitive emissions through the use of optical gas imaging ("OGI"). Operations in North Dakota would especially face feasibility issues in rural areas where there are often access complications and long distances between operations. In addition, the proposed requirement to use OGI equipment (or even Method 21 equipment in some locations) for monitoring fugitive emissions may require either consultants or specially trained in-house personnel to have to travel long distances to come back for repairs to leaking equipment that cannot be fixed immediately. While certain manufacturers and operators of OGI equipment and services may state that they can readily ramp up production or training necessary to meet operators' compliance needs, it is unlikely that this can happen in states like North Dakota that lack the people and resources that are more readily available in traditional oil and gas producing states like Texas and Oklahoma.

EPA acknowledges in the preamble to the Proposed NSPS OOOOa that there may be implementation issues due to the factors described above, but Commenters believes that EPA has underestimated the issues associated with the required use of OGI. EPA appears to assume that these issues will only affect small businesses, but Commenters' members believe that the required use of OGI will be infeasible for all operators. The infrastructure required to handle such activity in numerous, remote well sites presently does not exist. Optical imaging equipment costs between $80,000 and $100,000, the three-day certification is approximately $1800 per employee, not including the labor costs and travel expenses incurred. Currently, it takes a minimum of sixty (60) days to receive a camera once ordered. Commenters anticipates backorder delays associated with camera purchases if manufacturers are not prepared for the heavy demand. Commenters therefore urges the Agency to further evaluate the issues and costs associated with engaging consultants or training personnel for OGI, including the implications of requiring those persons to make multiple long-distance trips to numerous facilities and potentially facing access and weather issues along the way. Additionally, in some states climate creates unsafe weather and working conditions to adequately manage a fugitive emissions program. Imposing these regulations as drafted will negatively impact safety in order to comply with proposed timeframes. Due to extreme remote locations and extreme conditions, the ability to monitor, repair and re-monitor equipment is severely hampered.

Thus, EPA's proposed alternate "work practice standards" for fugitive emissions are neither "feasible" nor "practicable" and are therefore contrary to the CAA.

"Not feasible" is defined to include "not practicable due to technological or economic limitations." This provision indicates that a work practice proposed by EPA must be "feasible" and "practicable." For the reasons described above, the fugitive emissions work practices proposed by EPA are neither feasible nor practicable.

EPA should therefore withdraw the proposed work practice standards and instead work to develop a more flexible program referencing the methodologies employed under various existing state leak detection and repair programs. This flexibility would allow for more innovative and effective programs to be established over time rather than limiting operators to one BSER that is not only infeasible but may become quickly outdated as new methods are developed.

Response: The EPA disagrees with the commenter that OGI is not feasible or practicable standard under the CAA. The EPA has a long history of establishing fugitive emissions monitoring programs, and these rules are based on specifying the detection technology to be used. Fugitive emissions monitoring and repair is a work practice standard, which is an emission limitation that is not necessarily in a numeric format, such as the visualization of fugitive emissions using OGI, and is allowed under section 111(h)(1) of the CAA. We note in the final rule we have added the option to use Method 21 to detect fugitive emissions as an alternative to OGI.

We disagree with the commenter that our BSER analysis did consider technological and human resource limitations associated with addressing fugitive emissions through the use of optical gas imaging. We considered the cost of hiring contractors to perform monitoring surveys. We have also included costs for purchasing a Method 21 analyzer, planning, development of a monitoring plan, repair, resurvey, notification, and reporting. In addition we have information that shows there are several optical gas imaging contractors in each of the oil and gas producing states that are currently performing monitoring at well sites. We believe more companies will provide these services in the future. In addition, we have evaluated the cost of a company purchasing the optical gas imaging equipment and performing the inspections in house, which we determined to be higher than the contractor cost, but still reasonable. See Volume 1 of the TSD for the final rule (section 4) to view the cost evaluation of the contractor based and company owned optical gas imaging monitoring programs.

We disagree with the commenter that the work practice standards should be withdrawn. Most states that currently regulate fugitive emissions from oil and gas production (i.e., CO, WY, UT) require monitoring using OGI, Method 21 or another approved method capable of detecting VOC or methane emissions, which is what the final rule requires. In addition, we have added requirements to help promote the development of technology. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. Finally, in the final rule we have added a waiver provision for fugitive emissions monitoring at compressor stations located in certain areas of the country where average temperatures are subzero for an extended period of time. The waiver applies for only one quarter per year and is not extended to well sites, as we do not know of any areas where temperatures are subzero for six months at a time. Therefore, we believe that owners and operators should be able to meet the monitoring requirements through careful planning. See section VI.F.2.a of the preamble to the final rule for more information on this issue.

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number : EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 58

Commenter Name/Affiliation: Ben Shepperd/ Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 67

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 25

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 23

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 20

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 20

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 29b

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 28b

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 29b

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 29b

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 29b

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 8f

Comment: OGI cameras can be easily manipulated. For example, by adjusting the settings, an operator can make it more or less likely that the resulting image displays emissions. Even if EPA were able to control the process in a way that avoided such manipulation, the results are still highly dependent on the weather conditions at the time the camera is used, and variations in thermal activity could produce false evidence of a violation. OGI cameras can also generate false-positives, and simple changes in temperature can appear as fugitive emissions. These false positives could force operators to perform additional surveys, or make unnecessary repairs to correct non-existent leaks. By imposing nebulous restrictions on the weather conditions under which these surveys can be performed, EPA only further burdens the operators. As previously explained, well sites and compressor stations tend to be located in remote areas that are geographically distant from other facilities operated by the same company. As a result, personnel in charge of air compliance issues are not on-site at every well site or compressor station every day. If weather conditions necessitated rescheduling surveys at one or multiple well sites or compressor stations, the operator could find itself hard pressed to comply with the tight deadlines. In sum, the use of OGI technology creates a number of new problems for operators without creating a meaningful reduction in emissions.

Response: The commenters raise issues with OGI that have been considered and addressed by this rulemaking. Specifically, we have added requirements in §60.5397a for verification of the OGI equipment. This includes verification that the OGI is capable of imaging gases in the spectral range for the compound of highest concentration in the fugitive emissions and that the OGI equipment is capable of imaging a gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 grams per hour. In addition, the monitoring plan must account for daily verification checks, procedures for determining maximum viewing distance, procedures for determining maximum wind speed during which monitoring can be performed, determinations of thermal background, and procedures for dealing with interferences. We believe these procedures will ensure proper OGI operation and semiannual monitoring of well sites will provide meaningful reductions in both methane and VOC. We developed these requirements through technical studies that we conducted on OGI. See "Draft Technical Support Document – Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)"[1] for more information.

We do acknowledge that at certain temperatures, an OGI instrument may not operate properly or at all. Therefore, in the final rule we have incorporated a waiver for owners or operators that have compressor stations in areas of the country that have an average monthly temperatures below 0°F (based on historic climate data). If two of three months of a quarterly monitoring period each have an average temperature below 0°F, fugitive emissions monitoring is waived for that quarter.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 8

Comment: OGI Is A Cost-Effective Technology for Identifying Leaks in the Upstream Oil and Gas Sector But only Within a Properly Designed Regulatory Architecture. Noble has gained significant experience in the use of OGI technologies in detecting leaks in the upstream oil and natural gas sector, and in the timely repair of leaks. Initially, Noble's experience with OGI

[1] DCN EPA-HA-OAR-2010-0505-4949

technology was voluntary; it was designed to give the company experience with an emerging technology and was consistent with the company's commitment to going beyond regulatory requirements in reducing emissions. During the state of Colorado's 2014 rulemaking to adopt a technology-based LDAR program for the oil and gas sector, Noble provided testimony and evidence documenting the cost-effectiveness and utility of using OGI technologies to detect leaks, based on our knowledge at the time.

Based on its experience in the field, Noble currently believes that a properly designed LDAR program, such as the one Colorado developed, that relies upon OGI can cost-effectively identify and repair leaks in the upstream oil and gas sector.

Response: We agree that when properly operated, OGI instruments are cost-effective technology for fugitive emissions monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6789, Excerpt 17.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 18

Comment: In addition to monitoring frequency, there are other concerns with the proposed LDAR program. The proposal suggests relying solely on OGI or Method 21 for monitoring and repair—but such constraints are self-limiting and ignore existing, successful LDAR programs. OGI and Method 21 are reasonably effective technologies for LDAR applications; however they are imperfect and may not function well in all situations. For example, OGI is also not a quantitative tool and depending on the camera, it may also detect water vapor and heat signatures. An OGI camera survey may not always be able to tell an operator whether a repair is necessary since it is not quantitative. During periods of overcast skies, high winds, or inclement weather, OGI technology is unable to effectively detect hydrocarbon vapors. In certain parts of the West such overcast and windy conditions can persist for long periods during the winter. Lastly, OGI cameras are generally not intrinsically safe and would require a hot work permit in many instances. Thus, a prescriptive LDAR rule that relies too heavily on an OGI monitoring plan will be ineffective in many basins across the West for much of the year. While OGI cameras have their place in certain circumstances, they are inherently limiting in their utility within an LDAR program—particularly one so focused on defining leaks and leak percentages such as that being proposed. For a more effective LDAR program, the rule should give operators flexibility to select the ideal monitoring technology for the prevailing conditions.

Response: The EPA disagrees with the commenter. OGI and Method 21 are proven technologies for finding fugitive emissions in oil and natural gas production. We note that while the existing commercial OGI technology is not a quantitative tool, we define a fugitive emission as any visible emissions observed using the OGI instrument. We agree that OGI cameras should be used in an optimally defined zone of environmental conditions, which would not include periods of high winds. The final rule includes verification that the OGI is capable of imaging gases in the spectral range for the compound of highest concentration in the fugitive emissions and that the OGI equipment is capable of imaging a gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 grams per hour. In addition, the final rule requires owners and operators to provide the following information in their monitoring plans: daily verification checks, procedures for determining maximum viewing distance, procedures for determining maximum wind speed during which monitoring can be performed, determinations of thermal background, and procedures for dealing with interferences. While overcast skies may decrease the options for an optimal thermal background, the OGI instrument may still be used. As to the hot work permit concerns, EPA is aware of an OGI instrument that is rated for use in Class 1 & 2 in Division 1 and a Method 21 instrument that is rated for use in Class 1 & 2 in Division 1 &2. Alternatively, to alleviate the safety concerns, you may request an alternative technology that meets your site restrictions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 29

Comment: Technologies are readily available to identify and to help reduce these emissions. Technologies that enable rigorous leak detection are available today, and are continuously improving. Optical gas imaging (OGI) systems have rapidly advanced to the forefront of leak detection technology, primarily because of the speed with which these technologies can detect large leaks and other important advantages over Method 21 or non-instrument based methods. :

- **Speed.** OGI can be used to quickly and comprehensively scan an entire facility for leaks, thereby detecting improperly functioning equipment from a safe vantage point. The Colorado Air Pollution Control Division estimates that operators can scan a facility for leaks twice as quickly using an infrared ("IR") camera as they can using a Method 21-compliant device. Some experts suggest that this is a conservative estimate of the time savings associated with the use of OGI technology, and that OGI camera scans can be performed even more efficiently.

- **Comprehensive Inspection.** Moreover, OGI technology with IR cameras is proven to enable efficient site-level assessments, including difficult-to-access components. A clear illustration of this is that operators can detect leaks atop storage tanks using an IR camera that would otherwise go undetected unless an inspector climbed to the top of the tank. This allows open thief hatches or other malfunctions to be promptly addressed once detected, without requiring an inspector to climb the tank on every leak survey. In addition, as EPA recognizes, OGI can help operators detect sources of emissions, such as a crack or corrosion in a run of pipe or along the surface of a tank. Operators are not specifically required to inspect the equipment or locations of those sources covered under the program's requirements. 80 Fed. Reg. at 56,637.

- **Accuracy and Efficacy.** Although technologies such as OGI do not currently quantify leaks, detection itself is of primary importance, since most leaks are cost-effective to repair once detected. The quantitative comparisons that exist indicate that OGI is as effective as Method 21 in detecting all but the smallest leaks.

The establishment of OGI-based LDAR programs is a central feature of many leading state standards. Five states—Colorado, Pennsylvania, Ohio, Utah, and Wyoming—have adopted LDAR requirements for oil and gas facilities that allow the use of OGI instruments as a means of compliance. California has proposed quarterly LDAR standards at new and existing sources statewide that would require the use of OGI instruments. And since 2011, EPA's Reporting Program has allowed the use of OGI cameras to detect leaking components at above-ground facilities in natural gas processing, transmission, storage, and distribution, as well as at liquefied natural gas import/export facilities.

Many leading operators have also deployed OGI to help detect and repair leaks. Companies such as Shell, Anadarko Petroleum Corporation, and Noble Energy have indicated that they are utilizing IR cameras for LDAR purposes. More specifically, Jonah Energy's Enhanced Direct Inspection & Maintenance ("EDI&M") Program in Wyoming has been ongoing for the last five and a half years and includes a *monthly* LDAR program using instrument-based surveys (i.e., IR camera technology). This program has resulted in over 16,000 inspections and thousands of repaired leaks identified by IR camera technology and has a reported overall control effectiveness in excess of 75 percent.

At the same time as operators and states are applying OGI technologies, new technologies are emerging. The methane leak detection technology landscape is highly dynamic. ARPA-E's MONITOR project offers numerous examples of possible leak detection advances, sourced from a range of leading technology firms such as GE and IBM. EDF's Methane Detectors Challenge, in partnership with technology companies, large producers, and other stakeholders, is developing continuous detection of facility-wide emissions. Continuous detectors will cost-effectively and reliably identify leaks as soon as they occur, thereby allowing immediate repairs. Several of these technologies have accurately, continuously, and reliably detected methane leaks in controlled testing.

Figure 2, Correlation between Sensor Measurements from methane Detector Challenge Tests and Picarro Measurements of Ambient Concentrations (in ppmv methane).

Figure 2 below illustrates results from these recent tests. The figure indicates that the sensors from all of the innovators represented were able to detect leak concentrations within a narrow margin of error. Based on these strong testing results, the Methane Detectors Challenge is moving to pilot *continuous* detection systems at production facilities around the country. In the near future, low-cost continuous methane detectors may be commercially available to detect leaks.

As we describe more fully below, it is crucial for EPA's standards to incentivize development of innovative technologies that can deliver improved environmental performance at reduced cost. A robust alternative compliance pathway that creates an entry point for appropriately qualified detecting approaches will help catalyze a race to the top in technology, reduce costs for the regulated community, and potentially boost environmental benefits. States that currently require LDAR already allow for the use of approved innovative detection technologies to comply with regulatory requirements.

Response: We appreciate the commenter's detailed information on the effectiveness of OGI, including information on the specific use of OGI by oil and natural gas companies. As a part of this rulemaking, we evaluated the available state LDAR regulations for oil and natural gas production that either require or allow OGI to monitor for fugitive emissions. We have also finalized a process for the agency to approve alternate or emerging technology. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Mark Boccella, Americas Business Development Manager, Optical Gas Imaging
Commenter Affiliation: FLIR Systems, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-7063
Comment Excerpt Number: 2

Comment: Over the past 10 years, we have performed considerable research to gather information from our customer base regarding the effectiveness and affordability of implementing OGI programs across the globe. In doing so, we have found it reasonable to believe that operating a frequent OGI program can be a consistently economical way to realize low abatement costs for methane. This is of course a realization that puts more sales gas into the line, therefore increasing the profitability of the operator, which we find to be true for even smaller producers and low producing wells.

When analyzing the financial impact of such programs, it is relevant to consider the fact that the economic value of the conserved gas commonly exceeds the associated repair cost of the leaking equipment. A recent study by Carbon Limits, Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras, sheds light on the finding that 97% of leaks identified with OGI technology are profitable to repair even with the price of natural gas at $3/Mcf. Moreover, 90% of the gas emissions are from leaks that can be repaired with a payback period of less than one year. This study was based on data from 58,421 emissions sources at 4,293 Oil & Gas facilities across the United States and Canada.

This is consistent with what we are hearing from our customers. A specific example comes from one of our customers, Jonah Energy, who has operations in WY (Sublette County). Jonah Energy has publicly stated that their monthly Leak Detection and Repair program using OGI technology has not only been effective, but it has been consistently profitable. The cumulative gas savings realized by the program has exceeded $5 million in the past 6 years, which has more than covered the overall program costs. This includes the Optical Gas Imaging equipment and associated operators, along with all repairs and maintenance, including labor and parts. Recently, Jonah Energy shared their experience in the public comments submitted to the WY Depart of Environmental Quality Air Quality Division, saying:

"Each month, Jonah Energy conducts infrared camera surveys using a FLIR camera at each of our production facility locations. Since the implementation of Jonah Energy's Enhanced Direct Inspection and Maintenance Program in 2010, we have conducted over 16,000 inspections and have repaired thousands of leaks that were identified by the FLIR camera. Based upon a market value of natural gas of $4 per million Btu, the estimated gas savings from the repair of leaks identified exceeded the labor and material cost of repairing the identified leaks. Additionally, an estimate of hundreds of tons of volatile organic compound emissions have been eliminated from being emitted to the atmosphere.

The result of Jonah Energy use EDI&M Program has significantly reduced volatile organic compound and hazardous air pollutant emissions to the Upper Green River Basin airshed, has reduced the amount of sales gas lost due to leaks going undetected resulting in significant sales gas savings, and has reduced the number and severity of enforcement actions from the Wyoming Department of Environmental Quality due to fugitive leaks."

Response: The EPA thanks the commenter for the information that was provided. This information was helpful in our evaluation of the appropriate monitoring frequencies for well sites and compressor stations.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 7

Comment: EPA Should Include Fugitive Emissions from Reported Upsets and from Enforcement Investigations when Evaluating the Technical and Economic Feasibility of Options for Identifying and Controlling Leaks

So-called "malfunctions" at oil and gas plants can release very large quantities of methane and VOC's. While these upsets usually trigger flaring events that last for days or weeks, emissions can also be released from pressure relief valves, open hatches, gaps or holes in pipes or process equipment, or from onsite spills of liquid hydrocarbons. Texas facilities are required to report upset releases (as "emission events") online within 24 hours of their occurrence. Tables C-4 and C-5 of Appendix C include examples of fugitive or vented releases of reported VOCs from oil and gas sources that were allegedly caused by malfunctions. The data makes clear one or two upsets can release a large volume of pollution at compressors, boosters and gas plants.

Appendix C is based on a very limited subset of events that can easily be identified as releasing fugitive or vented emissions. Because they are rarely reported directly, methane emissions are estimated based on the methane content of the gas at each site where that information is available. Where it is not, the estimates assume a methane content of 65.7 percent of the weight of the natural gas composition.

EPA's enforcement program has published a "Compliance Alert" noting that "EPA and state inspectors have observed numerous instances of detectable emissions from controlled oil and natural gas storage vessels," due to inadequate design and poor maintenance practices, which in turn lead to backups that open relief valves that exhaust methane and VOC's to the atmosphere. Commenters urge EPA to evaluate these findings and the useful recommendations the enforcement program has made to address these recurring problems.

Response: We disagree that we should include reported upsets and enforcement investigations in the technical and economic feasibility evaluations. First, determining the amount of emissions that would be released to the atmosphere during these events would be difficult to estimate on a nationwide level. Second, we believe the implementation of a monitoring and repair program will reduce the number of upsets and enforcement investigations that would occur since potential malfunctions could be mitigated due to consistent periodic monitoring and repair of leaking components. Many of the events provided in Appendix C of the comments are from vents or pressure relief devices that have been actuated. Devices that vent as part of normal operations are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 17

Comment: Fugitive Emissions at Well Sites and Compressor Stations

Managing fugitive emissions or "leaks" from the oil and natural gas sector appeals to common sense. Leaks associated with natural gas operations represent safety concerns, negative impacts to the environment, and are wasteful from an economic standpoint. The industry has relied on audio/visual/olfactory (AVO) inspections for many years, and only recently has the industry focused considerable attention on technological advances to detect leaks. It is an emerging process – both in terms of technology and methodology (regulatory and corporate management). EPA's preamble bears this fact out with the number of specific requests for "comment" on the leak detection aspect of the proposal. IPAA/AXPC supports, in concept, the ability to satisfy the leak detection and repair (LDAR) requirements of the proposal with an appropriate "corporate fugitive monitoring plan," but a 60-day comment period (plus a random 17 days halfway through the comment period) is not enough time to create and implement such a program. Additionally, recent data and studies demonstrate that production fugitive emissions are characterized by a few sources ("fat tails") representing the overwhelming majority of emissions.

A handful of states are taking the lead on creating regulatory frameworks, each of which is different, and none of which follows the proposed EPA framework. Experience with the state programs is indicating that correction of fat tail emissions results in effective management of fugitive sources and, once corrected, the need for full-blown inspections/surveys more often than an annual frequency is unjustified. Even the states with the most aggressive LDAR programs are not focused on quantifying the total amount of methane "saved." The very nature of fugitive emissions makes it very difficult to quantify how much gas is being "saved." It is not as simple as a single point source with consistent flow where one can easily measure the emissions before and after controls are "bolted on" a stack or emission point. The component count at most facilities is likely in the hundreds to thousands, with only a very small percentage of the components leaking. For those that are leaking, the quantity of gas leaking varies considerably.

Nonetheless, EPA crunched some numbers in a hypothetical world and assigned some value to the natural gas that is saved. In reality, very few companies will realize any change in the sales meter pre- and post-LDAR. The savings are largely illusionary to the average operator. The value of the natural gas "saved" through the LDAR programs is highly speculative. In addition, EPA did not account for the size of the facility when estimating the percent savings. EPA's percentage saved calculations are based on Colorado's regulations and related data. Colorado's 80% reduction, which EPA adopts, is based on monthly inspections for facilities with less than 50 tons per year. EPA assumes, with no additional support, that their proposed regulations can achieve an 80% reduction from quarterly inspections for all facilities, regardless of size. IPAA/AXPC questions the validity of EPA's cost-effectiveness analysis for its proposed LDAR regulations.

Response: We agree with the commenter that managing leaks associated with oil and natural gas operations addresses negative impacts on the environment, as well as reducing safety concerns and economic losses. While we agree that "fat tails" are significant sources of emissions, there are other significant leaks that may not be discovered during periodic audio, visual, or olfactory (AVO) inspections. In addition, we believe periodic monitoring will reduce the number of "fat tails" by finding these leaks before they become significant leakers. To achieve significant reductions in methane and VOC, we believe national fugitive monitoring requirements are warranted. We are aware that some states have fugitive emission programs in place We carefully evaluated existing state and local leak detection and repair programs when developing these federal standards and attempted, where practicable, to limit potential conflicts with existing state and local requirements.

The potential emission reduction percentages used for the BSER analysis for the final rule are based on fugitive emissions data from the EPA Equipment Leak Protocol document and EPA's engineering judgment and not fully on the Colorado cost-benefit analysis. We reviewed data from the Colorado cost benefit analysis, ICF leak analysis, and calculated emission reductions by monitoring frequency and leak definition using data and procedures in the EPA Protocol document. In addition, we performed a sensitivity analysis based on the midpoints of the Method 21 emission reduction efficiency percentages, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. Even based on this conservative analysis, the EPA finds that the chosen monitoring frequencies are the BSER for these sources. The EPA additionally concluded that the 40, 60, and 80 percent emission reduction efficiency percentages are reasonable and accurate. See section 4.3.2.2 of the final TSD for further information.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 17

Comment: EPA should withdraw the proposed LDAR NSPS because it has not been developed based on the emerging experiences with fugitive emissions management programs, it locks in a technology approach that may be cost ineffective as experience with state programs evolves, and it would stifle the development of better approaches. Instead, EPA should work with states to learn from their programs and provide for a flexible voluntary fugitive emissions program in the Methane Challenge that would build a basis for a cost-effective NSPS in the future, if one is needed. At a minimum, implementation of any program should be delayed and EPA should work with industry to establish the necessary elements of a corporate fugitive monitoring plan that companies could adopt and customize to meet their particular needs while satisfying EPA's LDAR requirements. This performance-based approach would be the most effective and efficient.

Other than the handful of companies that provide the optical gas imaging (OGI) technology, industry is united in its position that EPA should not select or dictate the technology for detecting leaks. The concept behind NSPS is setting a performance standard that must be met – not dictating a particular technology. Dictating a particular technology stifles innovation.

There are approximately a half dozen or more additional technologies/techniques that are being marketed and/or developed including, but not limited to: tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas leak detectors; and remote methane leak detectors. These are in addition to the existing Method 21 procedure that some companies find workable and preferable. The need and motivation to "build a better mouse trap" will cease to exist if EPA dictates the technology, and there is no reason for EPA to select one technology. OGI/forward looking infrared (FLIR) technology suffers from numerous limitations. Perhaps most importantly, it is not inherently safe – if not used properly on site, it could cause an explosion. Additionally, the results of the camera, the "pictures", are difficult to interpret and subject to misinterpretation, e.g., what appears to be a leak could simply be a heat plume. These problems are exacerbated in windy and/or cold conditions that are prevalent in a number of the shale plays.

The technology is prohibitively expensive to smaller operators, and there is a limited supply of qualified service providers that can afford the camera. Even for the larger companies, at approximately $120,000 a camera, there will be a limited supply. For companies with diverse geographic locations, it will be difficult to comply with the short survey timeframes set forth in the proposal. The proposed regulations also require survey pictures to contain GPS coordinates. Some of the cameras do not have that function, thus requiring another device to comply with the regulations. Finally, the OGI technology is not a quantitative tool – it is not capable of determining how much natural gas is leaking.

Response: We disagree that the proposed fugitive emission requirements should be withdrawn. To address some of the commenters concerns, we have included changes in the final rule that allow operators to use Method 21 to perform monitoring. This should alleviate the commenter's concerns for companies that find the cost of purchasing an OGI instrument or hiring an OGI contractor to perform the required monitoring surveys cost prohibitive. We are aware of the multiple technologies listed (i.e., tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas leak detectors; and remote methane leak detectors). The technologies listed are generally too costly, cannot be universally applied due to technical limitations (e.g, necessity for hard target), represent incomplete solutions for fugitive emissions management (e.g, action levels for path averaged concentrations with varying path lengths), or lacking the supporting documentation (e.g, equivalence with proposed OGI, fugitive emission systems expected emission reductions). While we are not taking action on allowing these as the BSER or as an alternative, we encourage the continuing development of leak detection systems in this sector. We have also included requirements for the application of emerging technologies for monitoring fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 17

Comment: As discussed above, a number of states are taking the lead on LDAR programs and are learning how to effectively and efficiently implement controls and administer surveys. Despite repeated requests by IPAA during the Small Business Advocacy Review Panel process and other trade association requests for EPA's proposal to be consistent with and not duplicative of existing state LDAR programs, EPA's proposal runs roughshod over existing state programs. Inconsistencies and duplication in the proposed regulations and existing programs are burdensome, inefficient and costly – especially to small entities and independent operators. IPAA/AXPC specifically incorporates by reference the comments on the NSPS proposal of Anadarko which highlight the inconsistencies between the proposed Subpart OOOOa and existing regulations in Colorado and Pennsylvania. EPA's proposed regulations essentially punish states and operators within those states that proactively moved to address fugitive admissions. Such an approach does not make for sound policy. States with existing programs should be deemed sufficient, and compliance with the state program should be deemed as compliance with the finalized federal program. This is not a new concept in the context of EPA's NSPS for the oil and natural gas industry, and EPA should revise the proposed regulations to model the exemption for storage vessels in Subpart OOOO and deem legally and practically enforceable state LDAR programs to suffice for the proposed federal regulations. Such revisions would greatly reduce the regulatory burden for sources located in states that have proactively addressed fugitive emissions from the oil and gas sector. To the extent a party (whether EPA or a third party) believes an existing state program is inadequate, the burden should be placed on the entity making the allegation, and EPA should establish a process to address the complaint. Additionally, consistent with the CAA, the state programs should control, and EPA should implement procedures in the final regulations for states to submit for approval a state-based LDAR program that is deemed sufficient to satisfy EPA's final LDAR requirements.

Response: We are aware that some states have fugitive emission programs in place We carefully evaluated existing state and local leak detection and repair programs when developing these federal standards and attempted, where practicable, to limit potential conflicts with existing state and local requirements. Due to the differences in the sources covered and the requirements, determining equivalency through direct comparison of the various state programs with the NSPS has proven to be difficult. We also did not find that any state program as a whole would reflect what we have identified as the BSERs for all emissions sources covered by the NSPS. In any event, federal standards are necessary to ensure that emissions from the oil and natural gas industry are controlled nationwide. See State LDAR Comparison Memo in the docket for further discussion.

However, depending on the applicable state requirements, certain owners and operators may achieve equivalent or more emission reduction from their affected source(s) than the required reduction under the NSPS by complying with their state requirements. States may adopt and enforce standards or limitations that are more stringent than the NSPS. See CAA section 116 and the EPA's regulations at 40 CFR § 60.10(a). For states that are being proactive in addressing emissions from the oil and natural gas industry, it is important that the NSPS complement such effort. Therefore, in the preamble of the final rule, through the process described in section VI.K for equivalency determinations, owners and operators may also submit an application requesting that the EPA approve certain state requirement as "alternative means of emission limitations". The application would include a demonstration that emission reduction achieved under the state requirement(s) is at least equivalent to the emission reduction achieved under the NSPS standards for a given affected facility. Consistent with section 111(h)(3), any application will be publicly noticed, and the EPA will provide an opportunity for public hearing on the application and on intended action the EPA might take. The EPA will also publish its determination in the Federal Register.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the

American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 17

Comment: Another issue advocated by IPAA/AXPC and/or member companies prior to publication of the proposed rule was to not base LDAR requirements on arbitrary component count or percentage of components leaking at a given site – yet that is exactly what EPA proposed. EPA suggests that its proposal, which bases the frequency of surveys on the percentage of leaking components, provides an "incentive" for companies to be more vigilant in their identification and repair of leaks. As discussed above, the incentive to identify and repair leaks already exists, as there is a strong safety and economic incentive. EPA's proposal based on percentage of leaking components creates a recordkeeping nightmare.

The regulations are less than clear as to what constitutes a "facility" in terms of where to draw the line and stop the component count. As a result of the ambiguity in the proposal, it is difficult to evaluate if EPA's assumptions on components per well count are accurate. There is tremendous variability in the number of wells and types of equipment on well sites. For EPA to base its cost effectiveness on a "model well pad" is problematic. Member companies report component counts in the hundreds to thousands of components. Such a wide range is in part, a function of lack of clarity in the regulations and also calls into question the accuracy of EPA cost-effectiveness assumptions on a model plant. If EPA persists with a percent-leaking methodology, the regulations need to be clarified on what components are to be counted and how to define the limits of the facility for the component count. EPA's own evaluation concluded that quarterly surveys of the intensity proposed are not cost-effective. Yet, if more than 3% of the components are leaking, the proposed regulations require quarterly surveys. If quarterly surveys are not cost-effective, having more than 3% of the components leaking does not somehow make the quarterly surveys become cost-effective. Additionally, there is no direct correlation between the number of leaking components and quantity of emissions, so basing the frequency on the percentage of leaking components does not necessarily mean the program will be more effective at preventing fugitive emissions. While there is no direct correlation between the number of components and quantity of emissions, the component count/percent leaking ratio directly impacts the recording keeping requirements – again with no demonstrated reduction in emissions. It is just more paperwork compliance for operators.

Response: We agree that performance based fugitive emissions monitoring would require owners and operators to develop a complex recordkeeping program. We are not finalizing performance based monitoring but are requiring fixed monitoring schedules for well sites and compressor stations. See final rule preamble section VI.F.1.d and VI.F.2.c for more information.

We have also revised the definition of the well site and fugitive emissions component to address commenter's concerns and provide clarity to the final rule. See section VI.F.1.f of the final rule preamble and §60.5365(i) of the final rule for more information.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 17

Comment: Furthermore, leaks are often related to some sort of malfunction and once fixed, stay fixed such that there is no need or rational basis to increase the survey frequency. As EPA discussed in the preamble, experience with the state programs demonstrates there are "gross emitters" or "super emitters" that represent a very large percentage of the overall fugitive emissions profile (consistent with the fat tail issues discussed above). Preliminary information from companies with operations in states with aggressive LDAR programs already in place indicates treating every component "equally" is an inefficient use of limited resources. This information suggests that components subjected to constant or frequent vibration (such as components associated with a compressor) are much more likely to have leaks than say, threaded connections. And in terms of total component count at a given facility, there are likely to be many more threaded connections than the components most likely to leak at the relatively few compressors. Even if it is difficult to predict "gross emitters" or "super emitters" at any given facility, the knowledge gained from sources within states with existing LDAR programs suggests that treating all components equally and basing the frequency of surveys on leaking component percentages is inefficient from an emissions reduction perspective and extremely burdensome and costly – especially to small entities.

Again, more time to craft a regulatory program designed to identify and repair gross emitters would be preferred by IPAA/AXPC. Basing the frequency of surveys on the percent of components leaking exemplifies that EPA is largely guessing at what constitutes an appropriate LDAR program. EPA should not rush to judgment and instead learn from the state programs to determine the most effective and efficient way to reduce leaks. Alternatives include a performance-based approach such as that in Wyoming, basing the survey frequency on the size of the facility or the quantity of emissions leaked or perhaps a combination of a more technology-based annual survey with periodic AVO "inspections" between annual surveys. If EPA persists with the percentage-leaking-component approach, flexibility should be built into the program that companies could commit to semiannual surveys and not be subject to fluctuation from quarterly to annual surveys based on the number of components leaking. For some companies, the ability to plan for semi-annual reporting without the risk of quarterly monitoring would be more beneficial than the changing requirements and potential cost saving of annual surveying. However, for some smaller entities or independent operators, the ability to reduce surveys to an annual basis might be beneficial. Sources should be given the flexibility to choose. Flexibility in complying with the LDAR program will help reduce the cost and burden.

Individual components that are to be included for "fugitive" emissions monitoring must be better defined and differentiated from components that are designed to emit a certain amount of natural gas under certain circumstances. Further, components of the storage vessels, e.g., closed cover/vent/control systems, already covered under Subpart OOOO for storage vessels should not be subject to additional requirements. As some states have done, EPA should more clearly define and exclude components that are designed to release pressure for safety reasons, e.g., thief hatches and ENARDO valves.

Response: We have removed the performance based monitoring frequency requirements and have included a fixed frequency monitoring program. We believe a fixed monitoring program will reduce the number of "gross emitters" or "super emitters" by finding these leaks before they become significant leakers. Therefore, we are finalizing a semiannual monitoring program for components at well sites and a quarterly monitoring program at compressor stations. We have also removed the performance based monitoring provisions. We have also taken into account the costs associated with implementing a monitoring program and believe them to be reasonable.

We agree with the commenter that the fugitive components definition needs to be clearly defined and have finalized changes to the definition to remove equipment types and identify specific components, such as valves and flanges, which have the potential to be sources of fugitive emissions and that when surveyed and repaired would significantly reduce GHG and VOC emissions. This targeted list will remove the ambiguity of the proposed definition and will allow owners and operators to consistently identify fugitive emissions at well sites. See final rule preamble section VI.F.1.f for more information.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 17

Comment: Dictating a particular technology (OGI/FLIR) and then requiring the initial survey be conducted within 30 days (and repaired within 15 days) is an unreasonably tight time period – especially for smaller entities and operations with disperse and remote locations. These timeframes should be extended to 60 and 30 days, respectively. If EPA persists with the unrealistic time frames, a mechanism allowing for a "variance" on the time frames when certain circumstances exist should be built into the regulations. Even with companies with the resources to purchase a camera, their operations may be geographically dispersed or weather conditions are uncooperative such that they cannot realistically get from one location to the other. Smaller entities and some independent operators who cannot afford the dictated technology are then at the mercy of the market to comply within 30 days. Especially during the early implementation of the new rules, many sources are likely to incur enforcement/liability through no fault of their own due to an inability to purchase the technology or hire service providers with the necessary capabilities.

EPA's cost-effectiveness for the proposed LDAR program requirements is fundamentally flawed because it merely looks at the cost of conducting the survey and fails to accurately account for the increased record-keeping and reporting requirements. EPA's analysis is myopically focused on a straight up comparison of "cost-effectiveness" for semi-annual surveys versus annual and opts for semi-annual requirements because the relative cost-effectiveness is the same: $2,475 for annual versus $2,768 for annual under the single pollutant approach at the well site. EPA conducted similar comparisons for the multi-pollutant approach at the well site (as well as both comparisons at a compressor station). In every instance the annual survey was more cost-effective but EPA selected the semi-annual surveying because the cost/ton removed was similar. There are two problems with that philosophy. First – in selecting the semi-annual requirement, EPA basically double the cost of the requirement to industry. Second, the theoretical or modeled additional reduction in emissions is a very small percentage of the overall emission reductions associated with the proposed regulations. The additional cost associated with the annual survey requirement is substantial while the increased benefit to the environment is minimal. The additional regulatory burden will be disproportionately felt by small entities. The proposed LDAR requirements basically require all companies, regardless of size, to implement costly information systems to track and monitor compliance. For example, one of the larger, more sophisticated operators with a data management system already in place incurred an additional $10,000 in external costs associated with developing new or revised software, and an additional $37,000 associated with internal set-up costs and employee time focused on implementation. These costs were associated with complying with Colorado's LDAR program in a small gas field of 174 wells and, as indicated, were in addition to an existing management system at an estimated cost of $80,000 annually. It does not appear that costs such as these were considered in EPA's cost-effectiveness analysis. EPA's proposed requirements appear to be based on what is required at natural gas plants, and expanding that level of detail to remote, unmanned production sites is inappropriate. Such level of detail is not warranted nor has the cost been adequately justified – especially over the life of the well. The majority of the "benefit" associated with the surveying is on the initial startup of a well (or startup after modifications). It is impossible to calculate an accurate annual gas recovery rate over the life of a well site.

The new record-keeping requirements associated with the LDAR are particularly burdensome to smaller operators with limited staff. For example, the preamble provides limited to no justification for requiring the date-stamped digital photograph. If EPA retains the burdensome record-keeping requirements, companies should be allowed to keep the records on site or at a regional field office and produce them upon request. Companies should not be required to submit electronically or manually to the permitting agency. EPA requested comment on "ways to minimize recordkeeping and reporting burden." As discussed above, EPA should evaluate existing state requirements and liberally deem them sufficient for purposes of Subpart OOOOa and establish a mechanism for states to implement their own programs that supersede and satisfy Subpart OOOOa.

IPAA/AXPC supports the limited exclusions from the LDAR requirements that EPA has proposed but requests certain clarifications and expansion of the exclusions. Excluding low production well sites – defined as the "average combined oil and natural gas production for the oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production" -- is extremely helpful for small entities and smaller independent operators. IPAA/AXPC understands the 15 boe is also an "off ramp" – that is, when a well drops below 15 boe, it is no longer subject to the LDAR requirements. IPAA/AXPC requests the regulatory language be revised to indicate that when a well drops below 15 boe, based on a 30-day average production, the LDAR requirements no longer apply. EPA should provide an additional exclusion for well sites with component counts below EPA's model well site: below 548 components for gas well sites and below 135 components for oil well sites should be excluded from the LDAR requirements. EPA concluded that it is not cost effective to implement the proposed LDAR requirements on sites with lower well component counts and therefore those well sites should be excluded. Such exclusion would help all producers but would have greatest benefit to small entities that are likely to have smaller well sites. IPAA/AXPC also supports EPA's proposed exclusion for well sites with extremely dry gas where only the wellhead exists and there is no "ancillary equipment." IPAA/AXPC requests clarification that a meter and drip present at the well site do not constitute "ancillary equipment." Finally, in response to an EPA request for comment, IPAA/AXPC suggests that the LDAR requirements should only apply to those components that are directly connected to the fractured, refractured, or added well and should not apply to tank batteries or other equipment off the well pad which may receive fluids from the fractured, refractured or added well.

Response: We have made changes to the final rule that address the commenter's concerns. We have added Method 21 as an approved method for monitoring components at well sites and compressor stations. We have also extended the initial compliance date to 60 days and the repair time to 30 calendar days after detection of the fugitive emissions. We are also establishing in the final rule a process for the agency to permit the use of innovative technology for reducing fugitive emissions at well sites and/or compressor stations. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

To develop an NSPS, the impacts of the regulation must be evaluated. For the fugitive emissions portion of the NSPS, we used currently available methods to estimate emissions from well sites. We understand that these are emission estimates, but the methodology for estimating the fugitive emissions are based on the best procedures available for calculating fugitive emissions. We have compared the fugitive emission results with other studies and have found our results to be comparable to these studies. We have added an additional model plant for oil well sites with a gas to oil ratio (GOR) of greater than 300 standard cubic feet of gas per stock tank barrel of oil produced to increase the accuracy of the fugitive emission estimates. The percentages used for estimating fugitive emission reductions are based on information from Colorado. Additional information from states and fugitive emission studies has reported even higher emission reductions for periodic well site monitoring. Therefore, we believe that the percentages used for the impacts provide an appropriate estimate of the expected emission reductions from a fugitive monitoring program. We have also re-evaluated the costs associated with implementing a fugitive monitoring program to information received from commenters. These cost re-evaluations include the cost of implementing a company-based OGI monitoring program and the cost methodology used by Colorado in their analysis of fugitive monitoring. Based on this analysis, we determined that the OGI contractor cost methodology that we used for the impacts analysis for the proposed rule was lower than the company-based costs, but higher than the Colorado costs. Therefore, we believe that these costs are appropriate for determining the impacts for the final rule.

While the EPA has made some changes to the recordkeeping and reporting in the final rule, these elements are vital components of compliance assurance. We believe that the information that we are requiring owners and operators to document are necessary in order to determine how and the conditions under which the surveys are performed in order to determine whether owners and operators are performing surveys effectively. Records also provide information on the fugitive emissions that exist at the facility on an ongoing basis and whether owners and operators are in compliance with the repair obligations in the final rule. Because delegated agencies are unable to visit all regulated sites, reporting information is a necessary part of ensuring compliance. While we do not believe it is necessary to report all of the data recorded during the survey, we do believe that it is imperative to report data that allows a delegated agency to determine whether further review of records is necessary.

We did not receive data from the commenter showing that low production well sites have lower emissions than non-low production well sites. In fact, the data that were provided during the comment period for the proposed rule indicate that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable and we did not finalize the proposed exclusion of low production well sites from fugitive emissions monitoring. See final rule preamble section VI.F.1.b. for more information.

We disagree with the commenter that we concluded that it is not cost effective to implement the proposed LDAR requirements on sites with lower well component counts than the model plants. The model plants were used to determine BSER for well sites with some well sites have more components and some well sites having less components. We have included the exemption for well sites with only one or more wellheads.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 39

Comment: EPA's rationale for rejecting more frequent monitoring at well sites and compressor stations is flawed.

EPA has declined to adopt more frequent monitoring at well sites on the grounds that quarterly OGI inspections are not cost-effective for reducing VOCs and methane. 80 Fed. Reg. at 56,636. Although the agency's own analysis shows quarterly inspections to be substantially more cost-effective at compressor stations than other sectors, EPA nonetheless proposes less frequent surveys for these facilities based on its concerns with inspection equipment availability and small business impacts at these facilities. 80 Fed. Reg. at 56,637. Both of these rationales are flawed, and the agency should strengthen frequency requirements for these sources in the final rule.

Response: We revised the cost and emission reduction analyses for both well sites and compressor stations using information received during the comment period and updated equipment and component data from the GHG Inventory. Based on the re-evaluation, we determined that quarterly OGI monitoring for compressor stations and semiannual OGI monitoring for well sites were BSER. Commenters also provided information on the availability of OGI instruments indicating that instrument production could be ramped up to meet demand by the time the rule is implemented. We have added the use of Method 21 as an alternative to OGI for fugitive emissions monitoring. This will provide small businesses flexibility to choose the most cost-effective monitoring instruments for their fugitive emissions monitoring program.

Commenter Name: Mark Boccella, Americas Business Development Manager, Optical Gas Imaging
Commenter Affiliation: FLIR Systems, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-7063
Comment Excerpt Number: 9

Comment:

Section 60.5397a(c)(7)(i)(B); Pg. 425	Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤ 10,0000 ppm at a flow rate of ≥ 60g/hr from a quarter inch diameter orifice.

We believe this to be an oversight, as this diluted concentration is not indicative of what is being released during a fugitive emission event. Alternatively, it would be reasonable to require optical gas imaging equipment to be capable of imaging a gas that is pure methane or propane (≥98%) at a flow rate of ≥ 60g/hr from a quarter inch diameter orifice. The Alternative Work Practice uses a similar method, which we find to be unnecessarily complex but reasonable in principal.

A much more comprehensive and verifiable method would be the NECL method proposed in the Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K), August 11, 2015 which states:

> "Similar to the way in which the noise equivalent temperature difference (NETD) is used to characterize the performance of thermometric instruments by defining the smallest amount of temperature difference that can be definitively measured above noise levels (like the limit of detection in analytical chemistry), the NECL describes the performance limitations for OGI cameras in terms of the lowest ppm-m that can be detected above the baseline noise."

We fully support the NECL approach, as it is the most comprehensive method for comparing Optical Gas Imaging equipment and verifying their ability to visualize a particular gas of interest.

Additionally, this is a performance method that could be certified by the manufacturer upon production, thereby reducing the burden on industry.

Furthermore, there have also been references to a Daily Instrument Check for Optical Gas Imaging equipment. It is extremely important to note that as long as an OGI system turns on and is outputting an image, it will see gas with the same sensitivity and detection limit as it did on its manufacturing date.

This is mainly due to the fact that the internal "cold-filter" that allows an OGI system to target the absorption characteristics of hydrocarbon gases does not degrade or change properties over time. Only systems that quantify emissions should require a periodic instrument check, as they need to verify that there has not been any measurable drift to an existing calibration. Therefore, a daily instrument check for OGI equipment would unnecessarily increase the cost of implementing an OGI program, while offering no value in exchange.

Response: We appreciate the input from the commenter, however, we disagree with the suggested changes to the OGI verification procedures. While we agree there are advantages to the NECL approach for characterization of the noise limited detection capabilities of the sensor, the NECL approach only quantifies one aspect on the cameras ability to detect or visualize a particular gas of interest. The assumption, that as long as the OGI camera turns on and produces an image, is tied to a certain model and/or manufacturer and cannot be applied to all future versions of OGI instruments. We believe the verification procedures in the proposed rule provide assurance to the operator and to the regulatory authority that the monitoring was performed properly.

Commenter Name: Anonymous public comment
Commenter Affiliation: Anonymous public comment
Document Control Number: EPA-HQ-OAR-2010-0505-7064
Comment Excerpt Number: 1

Comment: Citation: §60.5397a(c)(7)(B)- Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60g/hr from a quarter inch diameter orifice.

Would be best if it read like below for initial verification part...this coincides with alternative work practice.

Comments or changes: Your optical gas imaging equipment must be capable of imaging methane gas that is at a mass flow rate of ≤60 g/hr from a quarter inch diameter orifice.

It would be optimal to be able to use pure propane in the daily calibration procedure. It is cheap & readily available (at Home Depot's, convenience stores, etc.). It allows industry to access the affordability of scale that manifest itself when commodities are made for the consumer. As opposed to methane cylinders

<u>**Reasoning and Background**</u>

EXAMPLE #1: Pure Methane

(desired grams) x 1 hr/60 min x 22.4 liters/1 mole x 1 mole/16.0425 = Pure Methane Flow rate in Liters/Minute

If desired minimal grams of Methane is 60 grams/hour, you would need a flow rate of 1.3963 liters/minute of pure methane to get a mass flow of 60 grams/hr.

If you are requiring a concentration of ≤10,000 ppm(i.e. 1%) ... you essentially move the above decimal 2 places to the right to get a needed flow rate of 139.63 liters/minute of 1% methane to equal a mass flow of 60 grams.

EXAMPLE #2: Pure Propane

(desired grams) x 1 hr/60 min x 22.4 liters/1 mole x 1 mole/44.096 = Pure Propane Flow rate in Liters/Minute

If desired minimal grams of Propane is 60 grams/hour, you would need a flow rate of 0.5080 liters/minute of pure propane to get a mass flow of 60 grams/hr.

If you are requiring a concentration of ≤10,000 ppm (i.e. 1%) ... you essentially move the above decimal 2 places to the right to get a needed flow rate of 50.80 liters/minute of 1% methane to equal a mass flow of 60 grams.

EXAMPLE #3: 50% methane 50% propane (average molecular weight = 30.06925)

(desired grams) x 1 hr/60 min x 22.4 liters/1 mole x 1 mole/30.06925 = PMixture Flow rate in Liters/Minutes

If desired minimal grams of equal flow rates of mixture (liters/min) is 60 grams/hour, you would need a flow rate of 0.7449 liters/minute of mixture (100% Methane & 100% propane) to get a mass flow of 60 grams/hr.

If you are requiring a concentration of each component of mixture ≤10,000 ppm or 1% ... you essentially move the above decimal 2 places to the right to get a needed flow rate of 74.49 liters/minute of mixture comprised of 1% methane and 1% propane to equal a mass flow of 60 grams.

Long introduction .. where I am going to with this is............. Pure propane flowing at ~0.5 liters/minute which is equivalent to 60 grams per hour should be the option or .... at a minimum take out the ≤10,000 ppm if you feel the need to prove that Optical Gas imaging (OGI) will see methane. It will see methane BUT, not at 10,000 ppmv certified concentration .... it may see a Method 21 value of 10,000 ppmv.. these are 2 different animals. A method 21 value starts out as pure product which will have enough absorption till diluted to "create a dark area" on image being viewed.

1) **This is important!!** ≤10,000 ppm of methane will not be seen by any IR camera at any flow rate much less the equivalent 60 gram/hr flow rate of ~140 liters/minute. You will see a pure leak of Methane flowing at ~1.4 liters/minute or 60 grams/hr with OGI.

2) The flow rate (~75 liters/minute) thru a 1/4 inch orifice will be "whistling".

3) Methane cylinders (even pure methane cylinders) take 2 weeks to 4 weeks for delivery and are expensive.

4) Pure propane cylinders are available everywhere and are cheap.

4) An AL120 aluminum cylinder will have around 140 cu ft. of a gas.... that is ~3964 liters..... at 75 liters/min (above mixture flow) .... that equates to ~52 minutes of calibration time ..... if this procedure is implied to be used as a daily calibration which has been discussed, a cylinder that takes up to a month to have delivered is gone in 10 working days assuming 5 minutes to do daily verification.

5) Below are the absorptive spectrum curves for C1 thru C6

Response: We disagree that 10,000 ppm leak of propane/methane cannot be seen with any OGI camera. In fact, we have shown both the FLIR GF320 and the OpGal EyeCgas as capable of detecting those concentrations and mass rates in the "Draft Technical Support Document – Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)"[2]. The majority of the issues raised by the commenter relate to the use of the one-time OGI capability test for daily verifications. While we do consider it a valid daily verification check, we have not required that a gas release for the daily verification nor the one-time criteria be used to ensure daily verification. We are retaining the requirements to ensure the OGI instrument is capable of gas at the specified requirement.

Commenter Name: Anthony J. Ferate
Commenter Affiliation: Oklahoma Independent Petroleum Association (OPIA)
Document Control Number: EPA-HQ-OAR-2010-0505-6810
Comment Excerpt Number: 8

Comment: Actual leak survey data on new sources suggest the majority of the leaks come from tank thief hatches and tank pressure vacuum safety valves (PVSVs). Some of the leaks are caused by excessive backpressure in the flame arrestor prior to the combustor. EPA should perform a cost/benefit analysis for a regulatory program focused on the operation and maintenance of the tank vapor collection system versus the current proposal.

[2] DCN EPA-HA-OAR-2010-0505-4949

Response: We appreciate the comment, however, the data that we have shows that fugitive emissions come from a variety of different components. For the purposes of this rule, we are targeting sources of emissions that cannot reasonably pass through a stack, chimney, vent or other functionally-equivalent opening (fugitive) such as valves, connectors, open-ended lines and pressure relief devices and can be mitigated through a well implemented monitoring and repair program. Emissions from thief hatches on uncontrolled storage vessels are typically the result of poor maintenance or operating procedures and are sources of vented emissions.

Commenter Name: Tom Michels
Commenter Affiliation: ONE Future
Document Control Number: EPA-HQ-OAR-2010-0505-6880
Comment Excerpt Number: 9

Comment: EPA should not mandate semi-annual Surveys as BSER for fugitive emissions. The EPA has proposed OGI technology with semi-annual survey monitoring as part of the BSER for detecting fugitive methane emissions from new and modified well sites and compressor stations. EPA asserts that "the costs between annual and semi-annual monitoring are comparable. Because semi-annual monitoring achieves greater emissions reduction, we focus our analysis on the cost based on semiannual monitoring." However, when reviewing the frequencies of LDAR in making its BSER determinations, EPA relied on the quantity of methane emissions reductions (as depicted above in Table 2) and not necessarily the cost-effectiveness ($/ton) as noted below in Table 3 (cost of controls presented below are without incorporating the revenues from gas captured).

The EPA proposed analysis clearly shows that annual LDAR is more cost-effective than semi-annual LDAR. A cost-effectiveness analysis provides a means of evaluating whether one technology or work practice yields reductions relative to resources spent. As noted earlier, one can realize significant cost reductions when adopting a nationwide LDAR program in lieu of EPA mandatory programs, mainly due to economies of scale and avoiding efficiencies by having a single program for operators to adhere to.

Once the initial survey is completed, unless the operator has specific knowledge to indicate otherwise, it should be assumed that the facility is not likely to develop significant fugitive emissions leaks for the next several years and recurrent surveys should not be required, especially since these new facilities will be subject to current NSPS OOOO and OOOOa standards anyway. The commenter submitted information showing the volumetric leak rate results of a company's annual LDAR program. Rather than mandating a specific frequency, ONE Future believes that operators employing an Alternative Program should be given the freedom to select the sites that should be surveyed based upon their knowledge of the operations and the propensity for particular components to develop significant fugitive emissions leaks. The operator would then re-survey approximately 20% of its affected facilities each year so that each affected facility is re-surveyed once every 5 years, or upon "modification" of the facility. Based upon industry experience with DI&M programs within the midstream, transmission and distribution sectors, we anticipate that associated costs will be significantly lower than the LDAR program surveys and reporting required under the Proposed Rule.

Response: While we agree that annual monitoring has a lower annual cost and cost per ton than semiannual or quarterly monitoring, we disagree that these monitoring frequencies should be BSER. The BSER determination takes into account the "best system" that is "adequately demonstrated," "taking into account … cost … non-air quality health and environmental impact and energy requirements." The BSER determination must also take into account "the amount of air pollution" and "technological innovation." Based on the analysis of the OGI monitoring frequencies, we believe that semiannual OGI monitoring for well sites and quarterly OGI monitoring for compressor stations meets these requirements for BSER and have included these requirements in the final rule. Please see final rule preamble section VI.F.1.a and VI.F.2.a for further additional discussion. Also see the TSD for more information on the costs and emission reductions for the finalized well site and compressor stations monitoring frequencies.

We disagree with the commenter's assessment that once an initial survey is completed, it should be assumed that significant fugitive emissions leaks are not likely to develop for the next several years. In some cases, the repaired leak will leak again, in addition to new leaks that develop from other components. The estimated emission reduction percentages that we used for our analysis are not based on single monitoring event, but are based on the emission reduction percentage that would occur over time depending on the monitoring frequency. The data provided by the commenter shows that annual LDAR reduces emissions reduces the volumetric rate of emissions by approximately 40 percent. We believe quarterly monitoring will reduce fugitive emissions by approximately 80 percent. See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for more information regarding the potential emission reduction from fugitive monitoring.

We disagree with the commenter that the rule must specify a maximum viewing distance for OGI monitoring, and believe that the company should specify the maximum viewing distance in their monitoring plan. A prescribed maximum distance would lock the technology development in place for OGI cameras. The company is better suited to determine this distance based on their knowledge of the individual sites, terrain and OGI instrument. Different OGI instruments may have larger detector arrays or the ability to zoom to different distances. We also believe that the current detectors may be capable of better detection with enhanced algorithms and the use of gimbals for enhanced camera stability. However, this distance will be reviewed by the compliance authority who will determine if this distance is appropriate. The monitoring plan also requires the inclusion of wind speed and thermal background measurements and thresholds during the monitoring survey. Regarding DI&M programs, please see DCN EPA-HQ-OAR-2010-0505-6953, Excerpt 7.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 3

Comment: EPA Should Strengthen the Fugitive Emission Survey Requirements for Well Sites and Compressor Stations

Commenters strongly support EPA's proposal to require facilities to monitor for fugitive emissions from well sites and compressor stations. The Proposed Rule's requirements will help reduce a significant source of emissions and wasted energy. We recommend that EPA strengthen the proposed monitoring requirements for well sites and compressor stations in the following ways, which will help further reduce emissions effectively and efficiently:

(1) Require quarterly leak detection surveys. EPA should require operators to conduct OGI monitoring on a quarterly basis for three quarters of the year, in compliance with the methodology proposed by EPA and the modifications recommended below. EPA should require that operators use Method 21 for the fourth quarter of monitoring.
(2) Specify the Maximum Viewing Distance for OGI Monitoring. EPA must establish a maximum allowable distance from the target component from which operators may use OGI equipment to detect fugitive emissions.
(3) Documentation of Operating Conditions during Survey. EPA must require operators to conduct each survey during normal operating conditions and require operators to document and report relevant process conditions during the period of the leak survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 12

Comment: EPA Can Reduce Costs by Requiring a More Targeted Leak Detection Program

EPA's data shows that the largest sources of leaking emissions are valves and pressure-relief valves (PRVs). Further, there are many fewer of these fugitive components at wells sites and compressor stations. If EPA determines that quarterly leak monitoring for all fugitive components is not cost effective, the agency should at the very least require quarterly surveys of valves and PRVs, while maintaining a semi-annual leak survey requirement for OELs and connectors.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute

Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 158

Comment: *Overestimate of Component Counts*

EPA's approach for estimating component counts for the model plant gas and oil well sites overstates emissions and emission reductions. EPA rounded up the average counts of major equipment per well site, as well as the number of wells per well site. The effect of rounding up the wells per well site and the major equipment per well site is an overstatement of the emission reductions.

Response: The model plant was developed to reflect the type of equipment that would be found at a typical well site. A typical well site would not have fractional equipment, but would consist of whole pieces of equipment. Many well sites share equipment, such as separators or tanks. Even though, this equipment is associated with one well site, there is still piping from the other well sites to this equipment. If average equipment counts were used, we would be unable to capture the components associated with piping to this equipment. Therefore, we believe that this approach provides a better estimate of the actual fugitive emissions from a well site, rather than using equipment averages. Since proposal we have updated our model plants. Specifically, we have revised the equipment and component counts for well sites and compressor stations based on the 2016 draft GHG Inventory.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 18

Comment: Fugitive Emissions From Oil and Natural Gas Production Well Sites

OGI is the new technology. The EPA needs to progress to mandating the best technology is utilized with fugitive emission surveys. Generally, OGI technology has higher accuracy, has greater efficiency, is safe, and a cost-effective method for detection and measurement of hydrocarbon fugitive emissions. (http://www.gastechnology.org/CH4/Documents/13-Terence-Trefiak-CH4-Presentation-Oct2015.pdf) While there's been much discussion, there's been no conclusion over what are harmful or more harmful, exposures to one or few 'spikes' of a contaminant or continual low level exposures. Therefore, we recommend the EPA structures technology preferences based on how to obtain the best information in any given emission situation.

Response: The final rule includes Method 21 as an alternative to OGI, which provides a choice of techniques that the facility can use to meet the fugitive emissions monitoring requirements. The final rule also allows for companies to apply for the use of new monitoring technologies.

See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 11

Comment: Definition of "visible emissions" is ambiguous in the proposed 60.5397a (a), EPA defines fugitive emissions as "any visible emission from a fugitive emission component observed using optical gas imaging (OGI)." Although a good tool, please keep in mind that OGI technology suffers from numerous limitations. Primarily, it cannot differentiate between heat and water vapor, and hydrocarbons, therefore what is visible through optical gas imaging technology may not necessarily be hydrocarbon emissions. Further, its performance is also very dependent on environmental conditions such as temperature, wind, and humidity, etc., ... Per the language in the proposed rule, and especially as technology advances in the future, any small detection with the camera would be considered a leak and would be calculated in EPA's performance based approach of percentage leaks detected to determine frequency. This will be an even lower standard to meet in the future and could have the possibility of bumping all operators into quarterly monitoring which EPA said in the rule is not cost-effective. Therefore, this creates the following problem: as the detection technology becomes keener, the standard will change within this rule, even if the rule doesn't change, and as a result, this will increase compliance cost burden for operators. This is more support for a fixed frequency as Pioneer recommends in G.ii. below. Another key limitation is that the infrared ("IR") camera cannot quantify emissions. EPA and operators cannot determine the volume of gas detected and potentially able to be capture and sold. Therefore, how can EPA rationally determine the cost-effectiveness to justify this new arbitrary performance standard? This is more support for the inadequacy of EPA's cost-benefit analysis as TXOGA and IPAA/AXPC elaborate on in further detail in their specific comments.

Response: EPA disagrees with the commenter that with a proper monitoring plan that OGI instrument and operator that you cannot differentiate between heat, water vapor, and hydrocarbons. With regard to the enhanced detection capabilities over time and performance based monitoring frequency, we have removed these provisions from the final rule and only require fixed monitoring frequencies for well sites and compressor stations.

Also, see response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 18.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 9

Comment: Optical gas imaging can "SEE" methane and VOC, along with water vapors, but it does not quantify or differentiate well enough regulate by or only with this technology.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6998, Excerpt 11.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 16

Comment: Unit Control Cost: The LDAR requirements as written result in exorbitant unit control costs. The indiscriminate protocol takes a 'test everything all the time" approach to emission control without regard to the resulting cost inefficiency. The rule requires an operator to continue frequently testing all facilities, even after significant effort has been expended to ensure proper operation of an individual facility or when a facility has no real potential for emissions of any significant amount. This demonstration of the law of diminishing returns is borne out in Apache's own experience with similar universal LDAR testing in Canada. Our leak identification and repair program in Canada found and repaired a reasonable number of leak points in the initial years of execution, but in subsequent years the vast majority of facilities tested through LDAR surveys were found to have little or no leakage at all. This demonstrates that EPA's proposed methodology is inefficient and wasteful.

The following 'Likely Scenario' as shown in Table 2 illustrates the discrepancy between emissions reductions and cost, and was constructed by applying the model of results of the Canadian LDAR program to our U.S. operations.

Table 2 Likely Annual Fugitive Reduction Based on our experience in performing these activities, the actual results of the agency's proposed protocol will essentially result in these diminishing returns, causing an enormous expenditure by industry with little environmental benefit. In fact, the expenditure of money and manpower in carrying out these surveying requirements on facilities that have been shown to function adequately will diminish the industry's ability to conduct other, more effective emission reduction efforts.

Response: The commenter provided "hypothetical annual fugitive reductions" but did not provide any data for the emission reduction costs or reduction percentages that are provided in the tables. The commenter did not provide a description of the LDAR program that was used in Canada. Therefore, we were unable to verify the emission reductions provided in the tables.

Data submitted during the comment period and studies identified in the White Paper show that the potential emissions from well sites are significant even for declining production wells. Therefore, we believe it appropriate to require semiannual monitoring for all production well sites. Please see section 4 of the TSD to the final rule for emission reduction and cost information.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 25

Comment: The PBPA estimates that to satisfy the proposed LDAR portion of the rule, costs at each site will increase between $4,000 and $6,500 each operating year. Additionally, under the proposed rules, facilities remain affected for the life of the facility. Within the first five years of a well being brought on-line, production declines by approximately 80%. For the 25-year lifespan of a typical facility, the LDAR program costs are estimated between $100,000 and $162,500. The last 20 years of a facilities life would have volumes less than 20% of the initial gas throughput, yet increased costs per year would be the same whether volumes were at 100% or less than 20%, leaving companies with 20% of the revenues to pay the same costs originally covered by five times those revenues.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6808, Excerpt 16.

Commenter Name: Shawn Bennett, Executive Vice President
Commenter Affiliation: Ohio Oil & Gas Association (OOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6921
Comment Excerpt Number: 7

Comment: Subpart OOOOa will significantly increase the LDAR requirements for certain well sites located in Ohio that were not required to conduct surveys because they were deemed de minimis for emissions based upon throughput and gas analysis. This will significantly increase costs for sites that have little if any environmental impact. As such, the proposed rules are unreasonable and not cost-effective for de minimis well sites. The proposed rules should be revised to exempt well sites that qualify as de minimis for emissions.

Response: We disagree with commenter's assertion that we should exempt wells that are "de minimis for emissions." The commenter did not provide emissions data for these type of wells for our consideration. See response to DCN EPA-HQ-OAR-2010-0505-6808, Excerpt 16.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 15

Comment: The second thing that I wanted to comment on was just kind of this reliance on OGI technology. New Source Performance Standards is one thing. MACT standards are another.

But there was a recently promulgated MACT standard for the gasoline terminals. And I don't know if you're familiar with MACT 6(b), but they rely on audio visual and on factory LDAR. And they find that sufficient for gasoline terminals.

We do use some OGI instruments. They are complicated to use. They require quite a bit of training, and I think our average cost on those instruments is about $120,000.

Response: We agree with commenter that training is needed to properly operate OGI instruments for fugitive emissions monitoring; therefore, the finalized rule contains specific operating and training requirements for using OGI instruments. See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 18.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 21

Comment: The other thing is that I am not sure you are going to get that much better data relying on the OGI versus AVO or just the plain FTE Method 21. And I guess I would kind of like to see the cost benefit. If you really think the OGI data is that much better, compare the cost of OGI to the cost of AVO or LDAR and -- or just the Method 21.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6808, Excerpt 16 and section 4 of the TSD to the final rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 111

Comment: Based on EPA's estimates, LDAR requirements for oil well sites are not cost effective. Therefore, oil wells should be exempt from the subpart OOOOa LDAR requirements. Similar to the proposed low producing well site exemption for fugitives under Subpart OOOOa, oil well sites should be exempt from the LDAR requirements. This is based on the costs, cost effectiveness, and benefits estimated for oil wells.

EPA's Cost Effectiveness Analysis for Oil Wells In the evaluation of the fugitive leak regulatory alternatives for well sites, EPA made their decisions based on the weighted average cost effectiveness of oil wells and gas wells. EPA clearly recognized the difference in emissions potential between oil and natural gas wells, as they developed different model plants. Yet, without any justification or rationale, they ignored these differences and lumped oil and natural gas wells into one category and decided that the costs were reasonable to regulate both. However, as shown in Table 27-3, there were significant differences in the cost effectiveness of OGI monitoring for oil and natural gas wells. EPA must re-evaluate the LDAR program options separately for oil wells and gas wells and make decisions on the reasonableness of the costs independently.

However, for oil wells, all the cost effectiveness values, with the exception of the methane cost effectiveness using the multipollutant approach, are above these thresholds. Gas streams at oil well sites have lower methane content than the representative composition used by EPA in their analysis. EPA also significantly underestimated the costs of an OGI monitoring program. In addition, the benefit-cost analyses performed by EPA also support the conclusion that oil well sites should be exempt. For these reasons, EPA cannot conclude that OGI monitoring is cost effective and must not finalize any LDAR requirements for oil well sites.

Therefore, EPA must not finalize any LDAR requirements for oil well sites. In their analysis, EPA did not define the criteria they considered in developing model plants for an oil well site versus a gas well site. API believes that, for the purposes of the applicability of these fugitive leak components, the API gravity and gas-to-oil ratio (GOR) are characteristics that can be used to define these "oil" wells that must be exempted from these fugitive emissions LDAR requirements. API proposes that a well site that produces oil with either an API gravity less than 18° or a GOR less than 300 scf/bbl be exempted.

Response: We disagree with commenters that oil wells should be exempted from the fugitive emissions monitoring and repair program. Oil wells have similar equipment and components that have the potential to have fugitive emissions. We have re-evaluated the BSER determinations for oil and natural gas production wells to include additional costs for monitoring and the development of a new model plant. We also updated the equipment and component counts using updated information from the GHG Inventory. We believe that these costs are reasonable and determined that semiannual monitoring was BSER for both gas and oil well sites. See section 4 of the TSD to the final rule for our BSER analyses for oil and gas well sites.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 155

Comment: *Omission of Additional Cost Elements for LDAR Program*

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey. EPA's cost analysis failed to consider costs associated with training, monitoring device calibration and transportation. These are not insignificant and should be part of EPA's assessment of the costs of the proposed requirements. As indicated in the comments on fugitives, additional costs based on data from companies subject to Colorado Regulation 7 were included to evaluate the impacts to net benefits. Annualized costs associated with semiannual OGI leak survey and repair based on the CO Regulation 7 estimates are $6,353/yr/well site, compared with EPA's estimate of $2,230/yr/well site. Table 2-1 [Cost comparison for Fugitive Emissions, provides comparison for well pads, oil well site and gas well site for methane emissions and annualized cost] compares the total annualized costs for fugitive emissions controls at well sites in 2025 using EPA's estimated control cost and ERM's corrected control cost incorporating industry information from CO Regulation 7. The estimated total annualized costs using ERM's corrected estimate is significantly higher–more than three times–than EPA's estimate reported in the RIA. ERM's cost estimate is documented in the fugitive controls comment section.

Response: For the final rule, we evaluated costs associated with hiring an OGI contractor to conduct monitoring surveys, the cost of company performed OGI monitoring surveys and monitoring surveys based on Colorado Rule 7's assumptions. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 111, section 4 of the TSD to the final rule and the OGI Cost Memo.[3]

Commenter Name: Peter Zalzal, Hillary Hull, Elizabeth Paranhos and Alice Henderson
Commenter Affiliation: Environmental Defense Fund
Document Control Number: EPA-HQ-OAR-2010-0505-7033
Comment Excerpt Number: 3

Comment: Cost-Effectiveness Analysis of Leak Detection and Repair

EDF commissioned ICF to develop a stochastic model to estimate the cost-effectiveness of leak detection and repair at different types of facilities, with the aim of better understanding variation across facility and equipment types. Accordingly, the analysis seeks to develop facility models that replicate real world situations and capture variations in these characteristics by using a Monte Carlo simulation to analyze facility emissions, reductions and costs.

EDF believes that these results demonstrate that more frequently, quarterly monitoring is cost-effective.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6884, Excerpts 111 and 155.

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[3] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA: Evaluation of Cost Methodologies for Optical Gas Imaging (OGI) Monitoring (April 6, 2016).

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 26

Comment: I would like to see vehicle miles traveled included for resurveying because a lot of these wells are remote maybe 100-plus one way from a located -- from a centralized office. And so that's actually going to be a pretty substantial cost to go back out there. I think that's about it.

Response: The costs we used to evaluate BSER for well sites and compressor stations reflect the full cost for performing OGI leak inspections charged at the time by external service providers to facility owners. The monitoring costs include travel costs to and from the site and the cost of preparing a report of the monitoring results. Repairs can be performed by company personnel during their periodic visits to the well sites. Therefore, we do not believe any additional travel costs are warranted for the OGI monitoring. See section 4 of the TSD to the final rule and the OGI Cost Memo for further discussion.

Commenter Name: Richard T. Metcalf
Commenter Affiliation: Louisiana Mid-Continent Oil and Gas Association (LMOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6853
Comment Excerpt Number: 6

Comment: The Unique Louisiana Geography

The proposed rule assumes all "affected facilities" are the same. A significant amount of the existing and new development of oil and gas and pipeline activities affected by these rules will occur in "remote" areas (wetlands, offshore, etc.).

It may take 3-4 hours to access a wetlands and/or offshore facility. This is a "one-way" number. This may be by both helicopter and/or boat. The cost of transportation, especially for the fugitives provisions, far exceeds the time spent actually doing the work. The proposed rule does not account for these costs versus the projected benefits.

The proposal also "assumes" electricity may be readily available. For the areas stated above, this is not the case for many Louisiana facilities. If it is available, it may not be at a "cost effective" rate.

The NSPS "reconstruction" provisions are also problematic for platform facilities as space is limited and the platforms may not structurally be able to accommodate various additional control options.

The final rule must give great flexibility (e.g. exemptions) for states like Louisiana who will eventually implement this rule to be reasonable in its implementation.

Response: Regarding the comment on the remote location of facilities, see response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26. This rule is only applicable to onshore oil and natural gas production; therefore, offshore platform facilities are not covered under this rule.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 26

Comment: The LDAR survey will more often than not be contracted to outside consultants who will charge mileage and per-diem in addition to hourly or day rates. Secondly, manufacturers of OGI cameras cite the limitations of making observations during inclement weather including high wind, overcast skies or blowing dust or snow. Each, or several of these severe conditions are frequently found in the Permian Basin. Should conditions for the OGI camera become unsuitable for observations, the consultant will have to depart, presumably back to their home office, and return once again, incurring additional travel costs. The PBPA would like to note that these estimates are conservative due to the broad geographic areas the affected facilities reside in and often are located miles from paved roads often on gravel or dirt roads that require all wheel drive vehicles.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26. We agree that OGI monitoring should not be conducted during certain climatic conditions. The final rule requires owners and operators to develop and implement monitoring plans that contain procedures for determining maximum wind speeds for which monitoring can take place. The monitoring plan must also contain a contingency for dealing with adverse monitoring conditions such as wind. This will allow owners and operators to schedule monitoring during optimal climatic conditions.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 34

Comment: Second, EPA significantly underestimated cost estimates for resurveys under its proposed program. EPA's estimate for the cost to resurvey repaired components incorrectly assumes that the re-survey would be completed while the contractor is still at the facility. EPA should consider the cost per component when the contractor leaves the site and must return days later for re-surveying , including costs of travel and additional contractor time, particularly in remote regions, such as Wyoming.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 116

Comment: EPA did not consider key costs to industry in assessing the cost effectiveness of leak detection requirements proposed.

In its cost analysis for the proposed control strategy for fugitive emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with conducting leak surveys, completing repairs, and maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans. Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including training of personnel, travel time and costs, and equipment maintenance (e.g. monitoring device calibration).

When the full costs of monitoring are considered, the leak detection program proposed is not cost effective for either methane or VOC. At a minimum, API recommends OGI-based surveys be no more frequent than an annual frequency for any affected sources. The exception to this is oil wells. There is no scenario where oil wells are cost effective. EPA should totally abandon the regulation of fugitive emissions at oil wells.

In the cost estimation for implementing the LDAR requirements under Subpart OOOOa, EPA underestimated the cost of conducting a leak survey at the model well site. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey conducted by a contractor for a single well per well site ($600/single well battery) as the basis of the leak survey costs. The cost of the survey based on the reference document would be higher than the value used in the analysis that represents a single well site ($600/single well battery) and lower than the value provided for a multiple well site ($1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range which would result in an estimate of $720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute

Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 118

Comment: EPA did not consider impacts of travel to/from sites by trained personnel. Oil and natural gas production operations, gathering and boosting facilities, as well as transmission and storage compressor stations are geographically dispersed. Costs and impacts need to consider the time associated with traveling to and from sites, vehicle and fuel costs, and resulting vehicle emissions to conduct recurring LDAR at all new or modified well sites or compressor stations. A company may have a third party group or specific in-house person doing the OGI monitoring that is different from the person doing the repairs. Although the majority of leaks are repaired when detected, there would be additional driving costs and impacts for leaks that cannot be repaired immediately and for conducting the resurvey after leaks are repaired.

According to survey data provided by 9 companies subject to Colorado Regulation 7, the average annual number of miles driven per basin for leak detection monitoring is 28,000, and the average annual transportation cost per basin is $34,785. API members conducting voluntary LDAR programs indicated an average of 15,000 miles traveled per basin, with an average annual cost of $21,000 per basin. These costs do not include purchasing additional vehicles to accommodate the required travel. Neither transportation costs nor costs for purchasing additional vehicles were included in EPA's evaluation of cost effectiveness.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 120

Comment: EPA significantly underestimated the costs of developing and maintaining the corporate and site-specific monitoring plans.

§60.5420a lists the notification, reporting, and recordkeeping requirements under the proposed rule. §60.5397a(b) requires that companies develop both corporate-wide and site specific fugitives emissions monitoring plans with the alternative of doing a site specific plan with elements of both the corporate-wide and site specific fugitives emissions monitoring plan requirements. EPA did not fully evaluate the complexities or the costs for developing and maintaining the proposed requirements in §60.5397a(c) and (d).

EPA has not included in the cost effective analysis for leak detection and repair any of the significant costs for developing and maintaining both a corporate-wide and site specific plan for every well subject to NSPS OOOOa, particularly with respect to EPA's expectation that component counts are to be included in the monitoring plan. The cost estimate of $3,468 for the monitoring plan is greatly underestimated considering the great amount of detail required for the 2 different plans.

Response: We are not finalizing corporate-wide or site specific monitoring plans. In the final rule, owners and operators will need to develop fugitive emissions monitoring plan for well sites and compressor stations within company defined areas. See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26 and the preamble to the final rule section VI.F.1.h for discussion on the monitoring plan.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 24

Comment: In addition plan requirements are very prescriptive and small business entities will, as noted, be reliant on contractors to prepare their plans. It is also noted that the labor rates and time requirements associated with the preparation of fugitive emissions monitoring plans presented in the TSD appear to be biased low (i.e., $3,468). Such a monitoring plan is estimated to take between 80 and 100 hours or more to complete. Using a more realistic contractor average rate for engineering resources of $80/hr, the cost just to prepare a plan could range from $6,400 to $8,000, and likely more.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 13

Comment: EPA states on page 56636, column 3, under section VIII G. 1. Fugitive Emissions from Well Sites that they "expect that most repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site". This is an unreasonable expectation that lowers expected cost to the producers. Oil and gas facilities are often remote and it is not economical to have a 3rd party repair crew follow OGI survey personnel in the potential that a repair may be needed.

Response: Although oil and natural gas facilities may have remote locations, company personnel periodically visit well sites for maintenance and other activities. Such activities can be coordinated to be completed during scheduled monitoring surveys to eliminate the burden of personnel having to come back to repair fugitive emissions components. Also see response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 31

Comment: While there will also be costs associated with resurveying using Method 21, we estimate that many companies own Method 21 instruments…" We believe that most of the owners/operators in the Illinois Basin do not own EPA Method 21 equipment. Requirements do not exist today that would necessitate owners/operators to own and maintain the specified equipment. We would be required to purchase and maintain EPA Method 21 equipment for compliance with this proposed regulation.

Most refineries utilizes a contractor to monitor emissions throughout the facility using EPA Method 21. The average annual cost to survey at refineries is greater than $10 per component, where the contractor reports to the same facility every day. We believe that our cost to survey or resurvey using EPA Method 21 could be $15 to $20 per component, which would include travel cost in addition to survey cost. We estimate that our compliance cost could be up to ten times EPA's estimated cost of compliance using Method 21.

One operator is our basin has approximately 2,200 well heads and 400 tank batteries spread over multiple states. If we estimate that each well head contains 50 Fugitive Emission Components and each tank battery contains 50 Fugitive Emission Components, their cost to complete one survey of each component could exceed $2 million each year (at $17 per component), utilizing EPA Method 21. This cost does not cover a higher frequency than annually, required repairs, resurvey, or reporting costs. If EPA only required EPA Method 21 as a survey method, the additional compliance cost would considerably change the way that we operate our company.

Response: The final rule requires fugitive emissions monitoring using OGI but also allows Method 21 (i.e. flame ionization or photoionization devices) as an alternative to OGI, which provides a choice of techniques that the facility can use to meet the requirements. See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 11

Comment: EPA Has Inflated its Cost Assumptions for OGI Contracting Services between 30 and 230 Percent

EPA estimates that a third party contractor would charge $600 to survey a well site and $2,300 for a gathering and boosting station, a transmission station and a storage facility. Based on conversations with two contractors, the actual cost is substantially lower, and EPA should amend its cost figures accordingly.

From conversations with contractors, as reflected in the attached rate sheet, the range provided for gathering compressor stations was between $1,000 and $1,750. The rate sheet also shows that the cost of surveying a well production site is about $350. Further, the contractors stated that they generally would discount from their standard price of performing a survey if the hiring company entered into a long-term contract for services.

The provided contractor's hourly rate further demonstrates that EPA has overestimated the cost to survey a compressor station. Based on EPA's data, it is reasonable to estimate that a standard survey of a compressor station would take approximately six hours. First, EPA estimates that a traditional Method 21 survey of a compressor station would take about eight hours. Second, several studies estimate that monitoring with OGI is more than twice as fast as Method 21 monitoring. Assuming that some of the time associated with a survey involves preparing materials before the survey, quality assurance and control, and preparing and submitting a report, a 75-percent overall time savings is reasonable. Based on a $250 hourly rate, the cost for hiring a contractor to perform a survey is approximately $1,500. EPA should use this data to reassess its cost analysis.

Response: The cost data provided by the commenter is based on conversations with two OGI contractors. The survey costs used in the TSD analysis are based on the current average market prices for purchasing such services and an estimated mark-up to reflect the facility owner's internal cost. These internal costs include not only procurement costs to contract a service provider, but also staff time that may be required during the field survey. The total survey costs assumes that this mark-up for internal costs is 50% of the cost of hiring the external survey providers (i.e., the total survey cost to operators is equivalent to 150% of the cost of hiring an external service provider to survey the facility). The monitoring costs include travel costs to and from the site and the cost of preparing a report of the monitoring results. We believe that the cost used in the TSD reflects the true cost of fugitive emission monitoring at a well site or compressor station. Also see response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 26 for more information.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 5

Comment: EPA Has Underestimated Fugitive Emission of Methane and VOCs at Natural Gas Well Sites

The preamble to the Proposed Rule provides estimates that methane and VOC emissions from equipment leaks at natural gas wells are 4.5 tons per year and 1.3 tons per year, respectively, based on AP-42 factors. The Agency has likely underestimated fugitive emissions from these sources, which in turn suggests that it has underestimated opportunities to reduce VOC and methane releases from equipment leaks.

Response: We recognize there is a range of fugitive emissions from well sites and compressor stations. The goal of estimating emissions was to use best available information to estimate fugitive emissions from these sources. Using the latest data from the GHG Inventory for equipment and component counts and AP-42 emission factors for oil and natural gas production, we estimated the baseline emission from natural gas well sites to be 5.5 tons per year of methane and 1.5 tons per year of VOC. See section 4 of the TSD to the final rule for further discussion on emission estimates.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 35

Comment: At a minimum, we recommend emission reductions of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. Colorado's reduction levels were the result of many stakeholders, including operators and NGOs working together to create adequate and achievable regulations. Thus, since operators are able to achieve these levels in Colorado, they can do them in every state, basin and play across the nation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17.

Commenter Name: Roy Rusty Bennett
Commenter Affiliation: Mehoopany Creek Watershed
Document Control Number: EPA-HQ-OAR-2010-0505-6816
Comment Excerpt Number: 12

Comment: Colorado's Air Quality Control Commission has adopted what is deemed to be the nation's best fugitive emission regulations and the industry is able to meet them. Therefore, we recommend adopting the same consistent emission reductions of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 14

Comment: In addition, EPA appears to adopt, wholesale, estimates made by the state of Colorado in support of its own 2014 rulemaking establishing a Colorado LDAR program. *Id.* (citing the Colorado Department of Public Health and Environment Air Pollution Control Division Initial and Final Economic Impact Analysis. EPA selected 80% VOC/methane emission reduction, to be expected from a quarterly frequency, 60% reductions from a semiannual frequency, and 40% reductions from an annual frequency). The Colorado estimations, however, were fraught with error, were based on simple extrapolations of exclusively annual monitoring data, and did not represent conditions actually experienced.

Colorado's estimates, which were based on inflated and inaccurate fugitive emission estimations and factors to begin with, assumed that LDAR benefits both increase with the frequency of inspection and remain constant over time. Neither of these assumptions is true. First, Colorado's estimates were based on EPA guidance that applied a "rule of thumb" assessment and did not actually conclude that benefits from an LDAR program increase with frequency or stay consistent over time. Second, the EPA guidance relied upon addressed fugitive emission reductions at chemical plants and petroleum refineries (not smaller, widely dispersed oil and gas production facilities), utilized outdated information, and employed simple averages as opposed to a more accurate distribution of components that would be expected at smaller oil and gas facilities. *See* 80 *Fed. Reg.* at 56,635 (EPA citing to a 1996 report to estimate fugitive emissions component counts). These and other errors combined to result in inaccurate estimates about the cost-effectiveness of the Colorado LDAR program and the ostensible benefits of increased monitoring frequency in particular, but EPA has relied on them without any qualification whatsoever.

Contrary to the conclusions drawn by EPA from the Colorado rulemaking, actual experience with that LDAR program at affected oil and natural gas facilities in Colorado demonstrates that: (1) following the implementation of an LDAR program, leak rate frequency found upon initial monitoring drops significantly during subsequent monitoring to less than 1 %; and (2) providing operators the flexibility to focus on high emitting and likely-to-emit components delivers the most cost-effective benefits. Experience also demonstrates that these low, post-initial-monitoring leak rates generally are sustainable over the long term. *See* Colorado Regulation. 7/Litigation Support, prepared for WPX Energy, Inc. by Trihydro Corporation, at 1-1 (January 6, 2015)

Response: The potential emission reduction percentages used for the BSER analysis for the final rule are based on fugitive emissions data and EPA's engineering judgment and not fully on the Colorado cost-benefit analysis. We reviewed data from the Colorado cost benefit analysis, ICF leak analysis, and calculated emission reductions by monitoring frequency and leak definition using the procedures in the EPA Protocol document. A sensitivity analysis was performed using these data and we concluded that OGI monitoring in combination with a repair program can achieve fugitive methane and VOC emission reductions by 40 percent on an annual monitoring frequency, 60 percent on a semiannual monitoring frequency and 80 percent on a quarterly monitoring frequency. For more information on this analysis, please see the fugitive monitoring section of the TSD. Also see response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 35.

Commenter Name: Anthony J. Ferate
Commenter Affiliation: Oklahoma Independent Petroleum Association (OPIA)
Document Control Number: EPA-HQ-OAR-2010-0505-6810
Comment Excerpt Number: 7

Comment: EPA has overestimated the number to leaking components from new sources. Our operators indicate that the actual leak rate for existing NSPS OOOO sites is substantially less (i.e., less than 0.1% leak rate) than the data cited in the preamble. EPA should recalculate environmental benefit for this proposal based on measured leak rates from new and modified sources only. EPA should also calculate the environmental benefit of semi-annual surveys versus annual surveys based on this same data.

Response: The leak frequency was used to estimate the number of components that would need to be repaired after a monitoring survey. The number of leaking components was then used to estimate the annual cost of repair and resurveying for the monitoring program. The 1.18 percent leak frequency from the Uniform Standards Memorandum[4] was selected as being representative of a typical leak frequency that would be found during equipment leak monitoring. For a well site, this leak frequency yielded a total of 4 leaks per monitoring survey. OGI monitoring data from the Fort Worth study, showed an average of 4.24 leaks found at each of the 375 well sites that were surveyed. Therefore, we concluded that the 1.18 percent leak frequency was appropriate to use for the annual repair and resurvey costs for OGI monitoring. The environmental benefits associated with the implementation of a fugitive monitoring and repair program were developed for annual, semiannual and quarterly monitoring frequencies. The results of these environment al benefit analyses are presents in the TSD for this final rule.

Data from leak programs in the SOCMI and refining sectors show that after the initial survey, leaks reoccur at components that were repaired, in addition to new leaks that form. The monitoring and repair programs are intended to limit the emissions from these reoccurring and new leaks through periodic monitoring. The emission reduction percentages are intended to show the long term emission reduction potential from a monitoring and repair program. We have determined that semiannual monitoring and repair for well sites and quarterly monitoring and repair for compressor stations are BSER.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute

[4] Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 123

Comment: API Members Find That Recurring LDAR Has A Diminishing Return

EPA assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in the initial and final economic impacts analyses and has also solicited comment on the approach. There is confusion between rulemaking presented by USEPA and Colorado on the origin of the 40, 60, and 80 percent emission reduction assumptions for tank OVI monitoring. Neither agency clearly substantiates the basis of their assumptions. In addition, EPA unilaterally changed the data from Colorado without justification. EPA should be required to produce the basis for these assumptions for industry review.

Additionally, on page 56635 of the preamble, EPA solicited comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies. API members find that recurring LDAR has a diminishing return [currently semiannually in proposed §60.5397a(g)]. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys.

The Colorado Regulation 7 data reduction assumptions are based on an assumption that annual inspections will yield an annual leaking component rate of 1.18%, 1.77% for facilities with quarterly inspection and 2.26% for facilities with monthly inspection schedules. These assumptions were based on the chemical manufacturing industry (Subpart VV) and do not fit with the LDAR data observed in the upstream oil and natural gas industry. API companies conducting voluntary LDAR programs have observed much lower initial leak rates, ranging from 0.18% to 0.84% leaks for annual LDAR.

Survey data provided to API by companies subject to Colorado Regulation 7 enabled a comparison of the percent of components leaking for different leak survey frequencies (first time, then quarterly or monthly advanced instrument monitoring mechanism (AIMM) surveys). Overall, the percentage of components leaking were less than 1% from the initial survey and then decreased with subsequent re-survey. In the first quarterly AIMM survey, on average 0.88% of components were found leaking. In the second quarterly survey, the percent of components counts leaking dropped to roughly half at 0.38%. The monthly AIMM survey showed the same trend, with the initial survey finding 0.70% components leaking and subsequent monthly surveys decreasing to 0.17% in the 5[th] month. **Note, that although the leak finds decreased with subsequent surveys, the cost of each survey remained the same.** The $/ ton control provided by the EPA does not reflect the dramatic decrease in the percentage of leaking components over time with subsequent surveys.

From a separate analysis, an annual voluntary OGI survey involving 3,300 wells and 63 compressor stations, showed a 25% leak reduction at production sites and a 35% leak reduction at compressor stations in year two of an annual monitoring program. Based on HiFlow emission measurements and the assumption that leaks would have emitted gas for 365 days, emission reductions per well in year one of the annual survey was 148 thousand cf or 449 scf/ well. In year 2 of the annual survey at production sites, there was a leak count reduction of 25% and a corresponding emission reduction of 25% compared to the initial survey year. For midstream compressor stations, the emission reduction volume was 204 thousand cf or 2.9 thousand cf/station in year one of the annual survey. In year 2 of the annual survey at compressor stations, there was a leak count reduction of 35% and an emission reduction of 55% compared to the initial survey year. API recommends annual surveying with no performance based adjustment to the survey frequency.

Response: The potential emission reduction percentages used for the BSER analysis for the final rule are based on fugitive emissions data from the EPA Equipment Leak Protocol document and EPA's engineering judgment and not fully on the Colorado cost-benefit analysis. We reviewed data from the Colorado cost benefit analysis, ICF leak analysis, and calculated emission reductions by monitoring frequency and leak definition using data and procedures in the EPA Protocol document. In addition, we performed a sensitivity analysis based on the midpoints of the Method 21 emission reduction efficiency percentages, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. Even based on this conservative analysis, the EPA finds that the chosen monitoring frequencies are the BSER for these sources. The EPA additionally concluded that the 40, 60, and 80 percent emission reduction efficiency percentages are reasonable and accurate. See section 4.3.2.2 of the final TSD for further information.

With respect to the leaking component percentages, we used data from the EPA Equipment Leak Protocol document. The 1.18 percent leak frequency was selected as being representative of a typical leak frequency that would be found during equipment leak monitoring. For a well site, this leak frequency yielded a total of 4 leaks per monitoring survey. OGI monitoring data from the Fort Worth study, showed an average of 4.24 leaks found at each of the 375 well sites that were surveyed. Therefore, we believed the assumed 1.18 percent leak frequency was appropriate to be used for the annual repair and resurvey costs for OGI monitoring. We did not have data available on the leak rate from new sources and we used the available leak rate data for oil and production sources. Based on data received during the comment period and information in the White Papers, we believe the assumed leak rate of 1.18 percent was appropriate for new sources.

The commenter did not provide any information on the type of instruments that were used for the monitoring surveys that they reference in their comment. Because Colorado allows the use of AVO for their surveys, it is difficult to compare the results provided by the commenter with leak results from a Method 21 leak detection and repair program. Also see response to DCN EPA-HQ-OAR-2010-0505-6810, Excerpt 7.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 13

Comment: EPA Admits a Critical Lack of Information on the Number of Leaks at Uncontrolled Facilities.

In estimating baseline emission levels, the background TSD and the draft CTG guidelines both rely on outdated information on the percent of components that are leaking. In both of these documents, EPA assumed a 1.18 percent leak rate for natural gas. The importance of this very uncertain assumption is highlighted in footnote 53 of the background TSD which states that EPA generally lacked information on the number of leaks at uncontrolled facilities:

> There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant.

Issuing regulations without a clear understanding of the magnitude of the problem underscores the weak basis and the premature nature of the Agency's decision to regulate.

More recent data show that the actual number of leaks at uncontrolled facilities is likely to be an order of magnitude lower than EPA estimates.

As noted above, EPA's assumed leak rate of 1.18 percent is based on a 2011 memorandum from an EPA contractor. An evaluation of the memorandum in turn shows that the leak rate assumption is based in part on a 1995 "Protocol for Equipment Leak Emission Estimates," confirming that the Agency is basing its analysis on outdated information.

Recent data collected by TXOGA members show that the frequency of leaks is likely to be an order of magnitude lower than what EPA assumed in its regulatory analysis. Data collected directly in areas subject to State regulation show leak rates that range from 0.05 to 0.20 percent – with an average leak rate that is an order of magnitude lower than the 1.18 percent used by EPA in this Proposed Rule. The significance of this finding cannot be understated. It demonstrates that EPA is basing its assessment of the need for a regulatory program and its proposed control options on inadequate data that incorrectly exaggerate the need and value of regulation. A more accurate assessment of baseline emissions may well show that the proposed regulatory control options are highly cost-ineffective and should be abandoned or severely revamped.

Response: No supporting data were provided by the commenter for us to analyze these assertions. The commenter also did not provide any information on the type of equipment that was monitored, the monitoring technology, or the procedures used to determine leaks. Therefore, we believe that the leak information based on historical LDAR data is appropriate to be to assess the potential emission reductions from a fugitive monitoring program. See also response to DCN EPA-HQ-OAR-2010-0505-6810, Excerpt 7.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 14

Comment: But we've been doing business now in Colorado for several years. They revised the Regulation 7 on the Front Range to include LDAR programs for oil and gas operations.

And so we did an initial round of surveys last summer, and then we went back and checked them this summer. And the information we have on the number of leakers on new and modified sources is substantially different than the numbers that you used in your economics here.

On about 15,000 components in Colorado, we have a leak rate of less than one-tenth of 1 percent. And you might find that kind of alarming. But if you think about it, it is new sites. So if they're built new, they should be operating fine.

But the thing that surprised us most when we went back this summer and did the same tests on the same facilities is it was unchanged, virtually zero leakers on 15,000 components.

Another separate study done by a company called QEP out of Wyoming, and they were up in the Powder River Basin, found the same thing.

So I guess I would ask the EPA to go back and revise the calculations based on existing LDAR data on new and existing sources, rather than using the data for old sources. Because I think that what you cited in the regulation is some pretty old data.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6810, Excerpt 7.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 122

Comment: EPA Overstated The Baseline Emissions And Emission Reductions

EPA significantly underestimated the costs of the proposed LDAR requirements. To compound the problem, EPA overestimated the baseline emissions and emission reductions, which causes the cost effectiveness estimated by EPA to be lower than actual conditions.

One manner in which EPA overestimated the emissions is in their approach for estimating component counts for the model plant gas and oil well sites. EPA rounded up the average counts of major equipment per well site, as well as the number of wells per well site. The effect of rounding up the wells per well site and the major equipment per well site is an overstatement of the baseline emissions as follows:

Gas well sites: Baseline emissions decrease from EPA's estimate of 4.54 tons CH4/yr/well site to an unrounded estimate of 3.18 tons CH4/yr/well site, or a 30% reduction in methane baseline emissions and corresponding emission reductions.

Oil well sites: Baseline emissions decreased from EPA's estimate of 1.09 tons CH4/yr/well site to an unrounded estimate of 0.70 tons CH4/yr/well site, or a 36% reduction in methane baseline emissions and corresponding emission reductions.

Response: The model plant was developed to reflect the type of equipment that would be found at a typical well site. A typical well site would not have fractional equipment, but would consist of whole pieces of equipment. Many well sites share equipment, such as separators or tanks. Even though, this equipment is associated with one well site, there is still piping from the other well sites to this equipment. If average equipment counts were used, we would be unable to capture the components associated with piping to this equipment. Therefore, we believe that this approach provides a better estimate of the actual fugitive emissions from a well site, rather than using equipment averages.

The same rationale applies to the rounding of the wells per site, in that a site cannot have a fractional number of wells. In addition, given recent trends in increasing intensification of drilling on pads in terms of wells per pad, rounding the number of wells per site up is a reasonable assumption.

The equipment count and component data used for estimating fugitive emissions from was obtained from the latest version of the GHG Inventory. These counts represent the latest information from the industry and we believe provides the best information for developing model plants for well sites. The AP-42 emission factors provide the best available data for estimating fugitive emissions from the production segment.

With respect to other fugitive emission sources, we amended the definition of "fugitive emissions component" to include fugitive emissions originating from sources other than the vent, such as the thief hatch on a controlled storage vessel. However, we were unable to quantify these fugitive emissions from these sources, and were not included in the estimated emission reductions.

Commenter Name: T. Howard
Commenter Affiliation: Indaco Air Quality Services, Inc., Durham, North Carolina
Document Control Number: EPA-HQ-OAR-2010-0505-6937
Comment Excerpt Number: 1

Comment: Unfortunately, the EPA's proposed rule is at least in part based on inadequate emissions information. The white papers used cite studies of methane emissions from production sites by the University of Texas done for the Environmental Defense Fund. These studies have since been shown to have critical instrumentation flaws, as documented in the attached paper and letter.

The initial UT study (Proc. Natl. Acad. Sci. USA 110:1776817773) shows overwhelming evidence of Bacharach HiFlow Sampler sensor failure which causes the sampler to greatly under report emission rates. The follow up UT study of pneumatic devices (Environ. Sci. Technol. 2014, 49, 633640) was done using only a pre and post project calibration of the meters used to make emissions measurements. Additionally, even though an independent test of those meters conducted while the project was ongoing indicated one read too low by a factor of three, the research team continued to use that meter without any further investigation into its problems until the end of the project, and then did not disclose the existence of that independent test.

The HiFlow sensor failure in the initial UT study further indicates that this problem may have also affected the EPA Subpart W Greenhouse Gas Reporting Program, since the Bacharach HiFlow sampler is the only commercially available high flow sampler, which is one of the approved methods for determining methane emissions in the transmission and storage modules.

Decisions on methane emission regulations from the oil and gas industry should not be made until these critical instrumentation issues affecting safety, health, and environmental impact have been resolved.

Response: The information from this study was summarized in the White Paper, but was not used in any of the analyses for fugitive emissions. There are other studies in the White Paper that show significant emissions from fugitive emissions from the production, gathering and boosting, transmission and storage segments.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 8

Comment: EPA Must Consider Ancillary Emissions Reduction Benefits That Can Be Realized by Using OGI to Detect Storage Vessel Violations

As discussed in Part II.A below, EPA and state regulators have observed many instances where PRDs, thief hatches, and other components at storage vessels are releasing large amounts of VOCs and methane in violation of NSPS Subpart OOOO. While these emissions are not technically fugitive emissions, EPA should still tally the emissions reductions that can be realized by detecting the illegal releases with OGI as an environmental benefit of leak surveys. A recent EPA Compliance Alert makes clear that venting from PRDs at storage vessels is a wide-spread problem. Further, an independent contractor has related his experience that venting from thief hatches on storage vessels routed to VRUs and flares are one of the larger sources of emissions he regularly finds at storage vessels. As discussed in more detail in section II.A below, EPA's proposed rules do not include sufficient compliance assurance measures. Therefore OGI is one of the only ways to detect these emissions and the potential reductions should count as a benefit of the finalized leak detection program.

While we believe that these emissions are released in violation of NSPS Subpart OOOO, to the extent these emissions are considered fugitive emissions, it is clear that EPA's cost-benefit analysis did not consider them. The only fugitive sources EPA considered in its cost-benefit analysis of controls for leaking equipment at well sites are gas wellheads, separators, meters/piping, in-line heaters, and dehydrators. Therefore, even if these emissions are not violations, EPA must count the potential to detect and reduce such emissions as a benefit of regular leak detection surveys.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 122.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 13

Comment: The proposed LDAR program relies on fugitive emission factors from AP-42 to estimate methane and VOC fugitive emissions from a typical oil and natural gas facility, and an oil well facility. The use of AP-42 emission factors vastly over-reports and over-estimates the typical level of fugitives at an oil and natural gas facility. EPA's inaccuracies in this respect are further compounded by the fact that this proposed rule applies only to new and modified sources that use state of the art components and equipment, and are designed to minimize leaks. The end result is an overly conservative and inaccurate estimation of fugitive emissions that skews the purported benefits from the rule and EPA's related cost-effectiveness claims.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 122.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 40

Comment: Well Sites. EPA recognizes that quarterly LDAR is more effective than less frequent inspections, *id.* at 56,635, and likewise estimates LDAR survey costs that are roughly in line with past analyses, *id.* at 56,636. The agency, however, estimates baseline emissions from its model well site that are substantially lower than other analyses. These unrealistically low baseline emissions substantially understate the benefits of LDAR and reach the incorrect conclusion that quarterly LDAR is not cost-effective.

EPA's model well site underestimates emissions in two important ways. First, the agency does not estimate fugitive emissions attributable to key sources that expressly fall within the LDAR requirements. EPA recognizes as much, noting that "[s]ince we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of fugitive emissions components that would typically be found at a well site." 80 Fed. Reg. at 56,635. Indeed, EPA defines "fugitive emissions component" subject to LDAR requirements as including "*any component* that has the potential to emit fugitive emissions" and specifically enumerates certain components like "valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters." *Id.* at 56,638.

This definition expressly includes important fugitive sources associated with tanks—like thief hatches and separator dump valves—but EPA's model well site does not attribute any emissions to these sources, which can be significant.

Second, EPA has determined cost-effectiveness based on a model facility that is far smaller (and lower-emitting) than many new well pads currently being developed. EPA recognizes that its methodology for estimating the average number of wells on a new well pad may have this effect, noting that "industry and state regulatory trends indicate that well drilling will likely become increasingly concentrated on sites, potentially leading to an increase in the average number of wells per well site." This problem is compounded by EPA's use of GRI data from 1996 to develop average site-level component and emissions profiles, both of which are lower than recent studies suggest and fail to account for large super-emitters. Additionally, in developing a model facility, EPA's methodology fails to exclude the facilities the agency has proposed to exempt, which results in an estimate that is further biased on the low end.

EPA's exclusion of key emissions sources and development of a small model facility yield a substantial underestimation of facility-level emissions, which, in turn, generate cost-effectiveness numbers that fail to recognize full benefits of performing more frequent LDAR.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 122. With regard to comment on activity counts, we have used the best available information to determine the number of affected sources. We have used algorithms and other assumptions to remove sources that are exempt, and we believe that these activity counts has removed the majority of these exempted sources.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 92

Comment: It's our position that methane leakage and venting from the sector is actually likely much higher than reported in EPA's inventory. Peer-reviewed scientific literature suggests that methane emissions leaking from various stages of oil and gas operations are at least double the estimates in EPA's emission factors.

Consequently, it is absolutely essential that methane from this sector be controlled, and be controlled quickly, through strong standards for both new and modified sources.

We think the rule's proposed leakage of up to 5 percent from some units is greatly excessive, and a methane leakage rate of anything greater than 2.8 percent would make the life cycle burning of natural gas in power plants more harmful, from a warming perspective, than coal;

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 122.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 14

Comment: EPA states on page 56637, column 1, under section VIII G. 1. Fugitive Emissions from Well Sites that they "did not find any non-air quality health and environmental impacts or energy requirements associated with the use of OGI or method 21 for monitoring, repairing and resurvey fugitive components at well sites." There are energy requirements to fuel vehicles to get to the locations as well as travel time and travel on remote roads in varying weather conditions. Can the EPA expand on what they mean by this?

Response: The statement is intended to say that fugitive emissions monitoring and repair requirements do not produce any air, solid waste or wastewater pollution. However, the commenter is correct that there is energy consumption associated with charging the OGI camera and for vehicle travel. For the final rule, we estimated the secondary emissions from travel to and from the site to perform the equipment leak monitoring. The secondary emission associated charging the camera were not calculated, because we do not have enough information to perform this calculation. See section 4 of the TSD to the final rule for more information on secondary impacts for fugitive monitoring.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 22

Comment: Comparison of control costs to other industries, referenced on page 56616, column 2, under section VIII A. How the EPA evaluates control costs in this action, is inaccurate due to number of and remoteness of locations. Costs do not appear to consider emissions from multiple vehicle visits to locations for initial surveys, repair resurveys, modification surveys, probable pre-inspection surveys, as well as repair crews standby time. Each of these results in fugitive dust emissions, NOx, CO, VOC and CO_2 emissions from vehicles that would likely be travelling often 100 miles round trip from a base to a site.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6474, Excerpt 14.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 16

Comment: EPA's Cost-Benefit Analysis Over-Estimates Reductions and Under-Estimates Costs**.** AGA encourages EPA to review the assumptions made to support its proposed standards for fugitive emissions from compressor stations. As noted above, AGA believes that EPA should consider more current data from compressor station Subpart W measurements as the basis for estimates of emissions and associated reductions. Similarly, EPA's TSD appears to include many assumptions that are not based on current operations and costs, or assumptions that are not well supported. AGA has provided EPA with several examples where support for EPA's assumptions is lacking, but notes that this is not an exhaustive list or a comprehensive review.

An over-estimate in emissions (and reductions) and under-estimate in costs would result in higher benefit estimates and lower cost estimates than will likely occur. For emissions assumptions, EPA should consider more current Subpart W data or clearly explain why this information is not appropriate. Reduction assumptions should be well documented. For costs, if EPA lacks realistic information it should solicit additional input on costs associated with developing plans, preparing reports, conducting surveys, completing repairs, and re-surveying.

Response: We disagree with the commenter that we overestimated the emission reductions and under estimated the costs for OGI monitoring. We re-evaluated the emission estimates for the compressor station model plants based on component and equipment count information obtained from the GHG Inventory and removed emissions from components that are not sources of fugitive emission (i.e., leaks from valves, connectors, PRDs). We also compared the emission estimates with emission estimates from the GHG Inventory and other studies and found them to be comparable. Therefore, we believe the emission estimates used for evaluating options for the NSPS are based on the best information available. We also considered the fugitive emissions monitoring program implementation cost data that were provided by commenters and revised our cost estimates. See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for more information regarding the potential emission reductions used for the final rule.

Commenter Name: Tom Michels
Commenter Affiliation: ONE Future
Document Control Number: EPA-HQ-OAR-2010-0505-6880
Comment Excerpt Number: 10

Comment: EPA should not mandate semi-annual Surveys as BSER for fugitive emissions. The EPA has proposed OGI technology with semi-annual survey monitoring as part of the BSER for detecting fugitive methane emissions from new and modified well sites and compressor stations. EPA asserts that "the costs between annual and semi-annual monitoring are comparable. Because semi-annual monitoring achieves greater emissions reduction, we focus our analysis on the cost based on semiannual monitoring." However, when reviewing the frequencies of LDAR in making its BSER determinations, EPA relied on the quantity of methane emissions reductions and not necessarily the cost-effectiveness ($/ton).

The EPA proposed analysis clearly shows that annual LDAR is more cost-effective than semi-annual LDAR. A cost-effectiveness analysis provides a means of evaluating whether one technology or work practice yields reductions relative to resources spent. As noted earlier, one can realize significant cost reductions when adopting a nationwide LDAR program in lieu of EPA mandatory programs, mainly due to economies of scale and avoiding efficiencies by having a single program for operators to adhere to.

Once the initial survey is completed, unless the operator has specific knowledge to indicate otherwise, it should be assumed that the facility is not likely to develop significant fugitive emissions leaks for the next several years and recurrent surveys should not be required, especially since these new facilities will be subject to current NSPS OOOO and OOOOa standards anyway.

The following provides a summary of annual LDAR surveys and measurements of the fugitive component leaks using the HI Flow at 53 midstream compressor stations for 2014 and 2015.

Table 4: LDAR and Hi Flow Measurements at 53 Compressor Stations

	2014	**2015**
Average (cubic feet per minute (cfm))	1.85	1.14
Median (cfm)	1.16	0.64

This company implements an alternative LDAR program and also takes an additional step to measure the leaks using HiFlow instruments. Leaks that are identified are fixed according to the company's LDAR protocol. The measurements above are on "as found" basis on the leaking components. Comparing the data for 2014 and 2015, this company found a 38% average reduction in total leaks from these 53 compressor stations. This data indicates that once leaks are identified and fixed by a LDAR survey, the leakage rates remain fairly low and it clearly indicates that any frequency more stringent than annual basis is unwarranted.

Rather than mandating a specific frequency, ONE Future believes that operators employing an Alternative Program should be given the freedom to select the sites that should be surveyed based upon their knowledge of the operations and the propensity for particular components to develop significant fugitive emissions leaks. The operator would then re-survey approximately 20% of its affected facilities each year so that each affected facility is re-surveyed once every 5 years, or upon "modification" of the facility. Based upon industry experience with DI&M programs within the midstream, transmission and distribution sectors, we anticipate that associated costs will be significantly lower than the LDAR program surveys and reporting required under the Proposed Rule.

Response: We disagree with commenter's assertion that once a leak is found and corrected that only annual monitoring is needed. Components at compressor stations are typically under high pressure and are accessed routinely thus providing greater opportunities for leaks and the need to monitor components on a more frequent basis. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 25

Comment: OGI is the new technology. The EPA needs to progress to mandating the best technology is utilized with fugitive emission surveys. OGI technology has higher accuracy, has greater efficiency, is safe, and a cost-effective method for detection and measurement of hydrocarbon fugitive emissions. It is time to move forward with the best available technologies. (http://www.gastechnology.org/CH4/Documents/13-TerenceTrefiak-CH4-Presentation-Oct2015.pdf) While there's been much discussion, there's been no conclusion over what are harmful or more harmful, exposures to one or few 'spikes' of a contaminant or continual low level exposures. Therefore, we recommend the EPA structures technology preferences based on how to obtain the best information in any given emission situation.

Response: When operated properly, OGI provides a cost-effective way to find fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 5

Comment: Optical gas imaging is an expensive and currently limited technology, especially when the proposed rule attempts to regulate miles of pipelines, prior to enacting these rules a study should be performed to examine if the technology is accurate enough to enforce and if imaging will actually help reduce methane and VOC emissions to a level that is economically justified.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 18. Also see the OGI Cost Memo and Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program Memo in the Oil and Natural Gas docket EPA-HQ-OAR-2010-0505.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 12

Comment: The controls required under the current NSPS Subpart OOOO already address the primary sources of methane emissions from equipment in the oil and gas sector. Given the anticipated volume of reductions that will be achieved by the new control rules, the fugitive emission monitoring surveys are unnecessary, and the costs associated with these rules are unwarranted. These requirements are further unwarranted for operators like Enterprise that already have a number of compressor stations which have LDAR integrated into their operating permits.

Response: We disagree with the commenter that current NSPS (40 CFR part 60, subpart OOOO) already addresses the primary sources of methane in the oil and gas sector. The current NSPS focused on the primary sources of VOC and other criteria pollutants, whereas this NSPS (40 CFR part 60, subpart OOOOa) addresses the primary sources of methane from the oil and gas industry. Furthermore, subpart OOOO does not regulate fugitive emissions from well sites and compressor stations. We determined that the fugitive emissions from compressor stations have significant methane emissions from components such as valves and connectors and that it is appropriate to reduce these emissions through a fugitive emissions monitoring and repair program. We acknowledge that several states have implemented leak detection and repair programs for compressor stations which we reviewed and evaluated during our analyses for the final rule. See discussion in the State LDAR comparison Memo in the Oil and Natural Gas docket.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 12

Comment: EPA Should Consider Emissions Information Reported Under Subpart W Of The GHGRP In Its Analysis And When Considering Whether Regulation Is Warranted.

As EPA recognizes, the Agency is collecting data from T&S compressor stations under Subpart W of the GHGRP, which requires annual leak surveys and compressor vent measurements for T&S compressor stations. Since 2011, thousands of measurements have been completed and reported to EPA. Because an objective of the GHGRP is to inform policy decisions, EPA should closely review Subpart W reported data to understand implications for this initial regulation of methane emissions from natural gas operations. Although Subpart W only captures a subset of compressor station facilities, emissions can still be compared to EPA historical estimates by comparing on a common "activity data" basis. In other words, because EPA estimates for T&S in the annual national GHG inventory are often based on facility counts or compressor counts, comparisons of historical estimates could be made against emissions per facility or emissions per compressor values. A cursory review of the data indicates as follows:

Focusing on "gross emitters" is warranted because a small number of measured leaks are responsible for the majority of compressor station leak emissions.

Emissions from centrifugal turbines with wet seal degassing vents are significantly less than EPA's national inventory estimate.

The first item supports focusing on gross emitters and considering alternatives such as DI&M, as AGA proposes above. The emission estimates for two affected sources – centrifugal compressors with wet seals and pneumatic devices – raise questions about the potential environmental benefit and the need for the proposed regulation. AGA recommends that EPA closely review emissions data from Subpart W and revisit its cost-benefit analysis in the Technical Support Document (TSD) based on more current emission estimates.

Response: We have reviewed the emissions data that we used to estimate fugitive emissions from compressor stations and have removed components that are intended to vent. We also compared the estimated fugitive emissions in the TSD with the GHG Inventory and other studies received during the comment period for the proposed rule and found them to be comparable to the estimates in the TSD; however, we have updated the component and equipment counts for compressor stations and well sites based on information from the Inventory. Based on the emissions and costs estimates, we determined that quarterly monitoring for fugitive emissions was BSER for compressor stations. See section 4 of the TSD to the final rule for further discussion. Also, see the response to DCN EPA-HQ-OAR-2010-0505-6983 excerpt 17 with respect to focusing on 'gross emitters" and DCN EPA-HQ-OAR-2010-0505-6953, Excerpt 7, regarding DI&M programs.

Commenter Name: Kelly Guertin, Senior Environmental Engineer, Environmental Management and Resources
Commenter Affiliation: DTE Energy (DTE Gas Company)

Document Control Number: EPA-HQ-OAR-2010-0505-7052
Comment Excerpt Number: 7

Comment: DTE Energy agrees with INGAA that EPA should accept INGAA's Directed Inspection and Maintenance (DI&M) Program as it provides for a robust alternative to the proposed leak monitoring and repair program. EPA has recognized DI&M as an effective programmatic approach that focuses on larger leaks under their Natural Gas STAR Lessons Learned document.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 9

Comment: During the development of GP-5, the DEP performed independent cost-effectiveness analyses for LDAR and leak quantification surveys for sources at natural gas compressor station, processing plant and transmission station facilities. Based on the cost information received from two vendors for the LDAR surveys, DEP estimated the cost-effectiveness for 5 percent leaking components at $41.96 per ton of methane reduced and $2.10 per ton of methane reduced for 100 percent leaking components.

Response: We appreciate the information provided by the commenter. We used this information in our evaluation of state LDAR programs to provide a comparison to the final fugitive emission requirements. See the State LDAR Comparison Memo available in the docket for this final rule, DCN EPA-HQ-OAR-2010-0505.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 38

Comment: EPA's own cost per ton estimates per control in the natural gas transmission and storage sector are exceptionally high. For example, EPA estimates that the cost for annual OGI monitoring is approximately $14,554 per ton of VOC (applying single-pollutant approach) and $7,277 per ton of VOC (applying the multi-pollutant approach). EPA should deem these costs unreasonable, and should determine that the natural gas transmission and storage sector should not be subject to any final NSPS OOOOa.

In development of NSPS OOOO, EPA evaluated (as required) the cost-effectiveness of implementation of its various program proposals. Importantly, in EPA's NSPS OOOO Technical

Support Document, EPA specifically determined that cost ranges for application of pollution prevention requirements that were $5,299 per ton of VOC or greater, were unreasonable and "rejected" the regulatory option.

Here, EPA proposes regulatory options for the natural gas transmission and storage sector wherein the cost per ton should be rejected due to the exceptionally high VOC "cost-effectiveness," which is really cost-ineffectiveness. EPA's estimates, which are likely underestimates, grossly exceed cost-effectiveness calculations EPA has recently considered (in a like rulemaking context) as unreasonable and as basis for rejecting the regulatory option. Based on these numbers alone, the natural gas transmission and storage sector should not be subject to any final NSPS OOOOa. In addition to these specific comments, Kinder Morgan incorporates by reference INGAA's comments regarding EPA's flawed cost estimates for implementation of NSPS OOOOa in the natural gas transmission and storage sector.

Response: This action amends the NSPS for the oil and natural gas source category by setting standards for both methane and VOC for certain equipment, processes and activities across this source category. We are including requirements for methane emissions in this action because methane is a greenhouse gas, and the oil and natural gas category is currently one of the country's largest emitters of methane. Therefore, both the cost per ton results for methane and VOC are considered in the BSER analysis. As the commenter notes, the cost per ton of VOC control is high ($30,606 per ton of VOC for quarterly monitoring at transmission stations, $13,348 per ton of VOC for quarterly monitoring at storage facilities), but the cost per ton for methane are reasonable ($847 per ton of methane for quarterly monitoring at transmission stations, $369 per ton of methane for quarterly monitoring at storage facilities). When the cost per ton calculations are weighted for compressor stations, the cost per ton is $802 per ton of methane and $3,540 per ton of VOC for quarterly monitoring. For more information on the cost per ton calculations, please see Chapter 4 of the TSD for the final rule. Both of these fugitive emission cost per ton values were evaluated to determine BSER for the transmission and storage segments.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 40

Comment: EPA underestimates the leak survey and equipment repair costs. EPA has underestimated the costs for implementing the leak detection and repair program. The commenter provided a Table 1 that outlines the discrepancies between EPA's underestimated costs and the costs calculated by Kinder Morgan through years of direct experience implementing Subpart W's required leak survey program.

Response: We re-evaluated the costs to implement an OGI monitoring program for compressor stations to address comments on the proposed rule. We also evaluated costs for a company owned OGI monitoring program and a monitoring program based on an approach that Colorado used for their cost benefit analysis of OGI monitoring. Based on the review of these different approaches, we determined that the costs we used for determining BSER for compressor stations in the proposed rule were appropriate. See the OGI Cost Memo available in the docket for this final rule, DCN EPA-HQ-OAR-2010-0505, for further discussion.

We agree that the potential emission reduction percentages used to evaluate the implementation of a Method 21 monitoring program are inconsistent. The values used to estimate these emission reductions were based on survey data from chemical plants. We re-evaluated these expected emission reduction percentages using the emission reduction approach in the EPA Equipment Leaks Protocol. We believe the calculated emission reduction percentages are more consistent in what you would expect from a Method 21 monitoring program. See the Method 21 Potential Reduction Memo, available in the docket for this final rule, DCN EPA-HQ-OAR-2010-0505 for further discussion.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 14

Comment: EPA drastically underestimated LDAR implementation costs and INGAA finds them unrealistic.

EPA's approach to estimating LDAR costs included: (1) developing uncontrolled emissions estimates for a model transmission "plant" (i.e., compressor station) and a model storage plant; (2) developing nationwide uncontrolled emissions estimates based on the model plant emissions estimates and estimated numbers of new T&S compressor stations; (3) developing nationwide annual emissions control/reduction estimates for different LDAR monitoring frequencies (e.g., annual, semiannual, and quarterly); (4) developing annual control cost estimates for different LDAR monitoring frequencies; and (5) calculating estimated cost of control as dollars per ton of methane or VOC emissions reductions ($/ton).

INGAA asserts that EPA's LDAR implementation/compliance cost estimates are consistently well below practical estimates of actual costs. [The commenter provided costs data for the development and implementation of a fugitive emissions monitoring program.]

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 40.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 16

Comment: EPA failed to consider the cost of service disruptions and cost of pipeline reimbursements for outages.

EPA failed to consider fully the costs associated with a pipeline operator's obligation to refund customers' monthly firm reservation (demand charge) credits during periods a pipeline must reduce service to conduct compressor repairs. When there is an interruption of service on a pipeline and the shipper cannot use the capacity, it reserved through the reservation charge. Pipelines are required to provide shippers credits against their reservation charges.

Since EPA's Proposed Rule would require a pipeline operator to complete leak repairs within 15 days and shut down every six months, regardless of the time of year or gas load, a pipeline operator may be forced to reduce firm transportation service, reducing pipeline reliability during high demand periods, in order to conduct the repair within the arbitrary repair timeline. This reduction in service carries significant costs to the pipeline operator. In one case, an INGAA member needed to reimburse customers $2.5 million in associated demand charge credits for a six-day outage/reduction in firm transportation service.

There also are added costs to pipeline customers and ultimately consumers associated with the cost of the gas that is removed (or vacated) from the pipe and the cost of new gas that must be purchased to replace the blown down gas.

Response: We disagree with the commenter that these costs need to be included in the cost per ton analysis. The final rule allows owners and operators to develop a monitoring plan that is specific for their affected facility and gives owners and operators 30 days to repair leaking components. For repairs that require a compressor station shutdown or is unsafe to repair during operation of the unit, the facility can place components that have been found to have fugitive emissions on a delay of repair for two years or until the next compressor station shutdown, whichever event occurs first. Scheduled shutdowns are part of the normal maintenance of the facility and we believe should not be included in the monitoring costs.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 18

Comment: EPA did not predict the costs if "modification" is triggered on existing compressor or compressor stations.

While INGAA cannot predict the precise number of existing compressor stations that could trigger "modification," it believes that the cost range could vary between $100,000 and $1 million dollars per affected existing compressor station. EPA did not include cost estimates for existing sources that might trigger modifications.

Response: Since a modification of a compressor station only occurs when a compressor is added to an existing facility or when existing compressors are replaced by a compressor or compressors with greater horsepower, we did not estimate costs for modifications since they would be similar to a new compressor station. Therefore, we did consider modification of existing compressor stations in the cost evaluation and in the impacts for the final rule, and believe the costs that we estimated are appropriate.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 11

Comment: In addition, reliance on the Colorado program's cost-effectiveness evaluation is erroneous. As the Alliance has pointed out before, the Denver-Jules (D-J) Basin in Colorado is a unique operating field, not reminiscent of many (if not most) other parts of the country. As the D-J is located near major population centers, operators enjoy relatively easy access to their facilities along well-established roads and highways, in a field with well-developed gathering infrastructure. These circumstances are more likely to reduce the costs and burdens associated with an LDAR program when compared with other, more remote oil and gas fields across the country. So even if the Colorado data, in fact, demonstrated cost-effectiveness across some or all of the Colorado-operated facilities, those findings will not necessarily translate nationwide, particularly given that travel costs and employee time are the single biggest drivers of an LDAR program's overall costs. Conversely, many of the production basins in the West are in remote locations far from major urban areas. We strongly caution EPA not to solely rely on Colorado's pre-rule estimates regarding the cost-effectiveness of the Colorado LDAR program and Colorado's conclusions about how (if at all) frequency and consistency of LDAR inspections relate to emission reductions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for more information regarding the potential emission reductions used for the final rule.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 13

Comment: EPA's Cost-Benefit Analysis Over-Estimates Reductions and Under-Estimates Costs.

AGA encourages EPA to review the assumptions made to support its proposed standards for fugitive emissions from compressor stations. As noted above, AGA believes that EPA should consider more current data from compressor station Subpart W measurements as the basis for estimates of emissions and associated reductions. Similarly, EPA's TSD appears to include many assumptions that are not based on current operations and costs, or assumptions that are not well supported. AGA has provided EPA with several examples where support for EPA's assumptions is lacking, but notes that this is not an exhaustive list or a comprehensive review.

The "model plant" uncontrolled emissions are likely biased high. The estimates are based on the 1996 EPA/GRI study on methane emissions from natural gas operations. Those data were acquired from existing facilities over 20 years ago and are not representative of current operations, especially for a new facility that would be subject to Subpart OOOOa.

The estimated fugitive emission reductions may be erroneous and may be biased high. EPA references a Colorado Air Quality Control Commission (CAQCC) report that estimated the percent reduction for different monitoring frequencies. However, there are questions regarding the CAQCC report because the projected reductions are not based on a study that documents reduction performance as a function of survey frequency. The CAQCC estimates are not well supported. In addition, although EPA's assumptions do not exactly match the CAQCC report, the basis for EPA's deviation is not explained. Since the assumed reduction is not clearly documented, it may be erroneous. Since the uncontrolled emissions are likely biased high, it is likely that the associated reductions also are biased high.

LDAR implementation costs are biased low. Labor rates and time estimates do not reflect real-world costs such as time to review and understand the rule, develop a monitoring plan, prepare notification of compliance status reports, procure instrumentation, complete a resurvey, etc. By not addressing these tasks any estimate significantly under-estimates costs. This is demonstrated by two specific examples from EPA's TSD: (1) EPA estimates one hour for preparation of a compliance status report and (2) for the re-survey of repaired leaks it appears that EPA assumes a single instrument would be used for many facilities and peripheral costs associated with calibration gases, etc. are not included. These estimates do not reflect real-world costs.

An over-estimate in emissions (and reductions) and under-estimate in costs would result in higher benefit estimates and lower cost estimates than will likely occur. For emissions assumptions, EPA should consider more current Subpart W data or clearly explain why this information is not appropriate. Reduction assumptions should be well documented. For costs, if EPA lacks realistic information it should solicit additional input on costs associated with developing plans, preparing reports, conducting surveys, completing repairs, and re-surveying.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 40.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 25

Comment: In addition plan requirements are very prescriptive and small business entities will, as noted, be reliant on contractors to prepare their plans. It is also noted that the labor rates and time requirements associated with the preparation of fugitive emissions monitoring plans presented in the TSD appear to be biased low (i.e., $3,468). Such a monitoring plan is estimated to take between 80 and 100 hours or more to complete. Using a more realistic contractor average rate for engineering resources of $80/hr, the cost just to prepare a plan could range from $6,400 to $8,000, and likely more.

Response: In the final rule, owners and operators have the ability to define the area that each fugitive emissions monitoring plan would cover. This will allow owners and operators the flexibility to group well sites or compressor stations together within a geographical area such as within a production field or district for monitoring purposes. See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 40.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 10

Comment: EPA Should Not Assume that Individual Compressor Stations Will Purchase Separate Method 21 Devices

With respect to EPA's cost estimate of using Method 21 technology for leak detection surveys, Commenters also raise the fact that EPA should not estimate the cost as if each individual compressor station facility requires its own device. Rather, it is common that operators of compression stations operate multiple facilities subject to the Proposed Rule in close proximity to each other and therefore need not purchase separate Method 21 devices for each facility.

Pursuant to the Proposed Rule, operators are required to resurvey equipment that is repaired after a leak is detected using OGI or Method 21. EPA's cost analysis assumes that companies will purchase separate Method 21 devices for every single compressor station site. This is an unreasonable assumption as many companies operate compressor station sites in close vicinity with each other.

Similarly, as discussed in Part IV.A below, Hess operates six compressor stations surrounding its Tioga Gas Plant in North Dakota. EPA already has a precedent of assuming the shared use of detection equipment by operators of nearby well sites. EPA should apply the same reasoning to its cost analysis for compressor stations and apportion the costs of purchasing a Method 21 device across multiple facilities.

Response: In the final rule, owners and operators have the ability to define the area that each fugitive emissions monitoring plan would cover. This will allow owners and operators the flexibility to group well sites or compressor stations together within a geographical area such as within a production field or district for monitoring purposes where one Method 21 device could serve multiple compressor stations or well sites.

See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 40. Also see the Method 21 Potential Reduction Memo available in the docket for this final rule, DCN EPA-HQ-OAR-2010-0505, for further discussion.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 55

Comment: Several of EPA's calculations under this approach demonstrate the unreasonableness of EPA's assumptions. For example, EPA calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. EPA found the following cost-effective estimates reasonable, but provided no discussion justifying adoption of a requirement where the cost per ton of reduction would be approximately five (5) times greater for VOCs than for methane:

- "Based on an annual frequency (option 1a), the single-pollutant cost of control, with consideration of savings for gas recovery, was calculated to be $471 per ton of CH4 and $2,338 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $236 per ton of CH4 and $1,169 per ton of VOC."
- "Based on a semiannual frequency (option 1b), the single-pollutant cost of control, with consideration of savings for gas recovery, was calculated to be $504 per ton of CH4 and $2,510 per ton of VOC. The multi-pollutant cost of control, considering savings for gas recovery was calculated to be $252 per ton of CH4 and $1,255 per ton of VOC."

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 38.

Commenter Name: Anonymous public comment
Commenter Affiliation: Environmental Defense Fund
Document Control Number: EPA-HQ-OAR-2010-0505-6985
Comment Excerpt Number: 1

Comment: Comment is a PPT presentation by ICF International, dated Dec 4, 2015 of "Leak Detection and Repair Cost-Effectiveness Analysis", prepared for Environmental Defense Fund.

The presentation outlines a project that is consists of a Stochastic LDAR analysis of cost effectiveness of LDAR at well sites. The analysis uses a Monte Carlo simulation model to analyze emissions, reductions and costs using various values for: sizes of facilities, component counts, counts of leaking vs. not -leaking components, leak detection cost for in-house and third-party contractors, leak repair costs by component, whether replacement or repair, and other costs including travel and per diem, recordkeeping and reporting, survey time, and survey equipment and training. The project also analyzed the impact of emission reductions and cost over time.

Response: We appreciate the information provided by the commenter and have reviewed the data in the re-assessment of cost and emission reduction for fugitive monitoring.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 11

Comment: EPA's Cost-Benefit Analysis Is Flawed and Incomplete.

EPA's technical support document (TSD) includes EPA's estimates of control costs and cost effectiveness, including costs for proposed LDAR requirements to control fugitive methane and VOC emissions from T&S compressor stations. INGAA believes that EPA overestimated uncontrolled model plant emissions and fugitive emissions reductions, and underestimated the costs for LDAR implementation. INGAA recommends a complete review and revision of the analysis, and asks that EPA consider more current emission estimates, including information available from the GHGRP.

EPA overestimated uncontrolled model plant emissions.

EPA's estimate of model plant methane and volatile organic compound (VOC) fugitive emissions are based on component counts and emission factors from the 1996 EPA/GRI study. Therefore, these emission factors are based on data collected only at pre-1996 T&S facilities and do not represent a new T&S facility. Further, the leak rates most likely over-estimate emissions from current existing facilities that have adopted leak monitoring practices over the past 20 years.

It is likely that EPA could improve emission estimates for existing model plants using leak data recently collected for Subpart W of the GHGRP. Initial review of that data indicates current emission estimates from existing facilities are lower than EPA's model plant (based on 20 year old data). Emissions would be even lower for a "new" model plant compared to existing facilities.

Response: We reviewed data from subpart W and the GHG Inventory and found that the data from these two sources are based on the EPA/GRI study. Therefore, no changes were made to the source of data for the fugitive emission estimates. We did however, remove sources of emission from compressor stations that are intended to vent, and therefore are not fugitive emissions. We also updated our model plant based on equipment and component information contained within the GHG Inventory.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 13

Comment: EPA overestimated fugitive emissions reductions by citing a flawed Colorado study.

To estimate fugitive emission reductions as a function of LDAR monitoring frequency, EPA references a Colorado Air Quality Control Commission (CAQCC) Economic Impact Analysis. There are two fundamental problems with EPA's reliance on the CAQCC analysis. First, sources relied upon by the CAQCC are undocumented. CAQCC references data having been obtained from EPA, but provides no documentation regarding the actual source of the data on which it relies. Second, while EPA references the CAQCC analysis as its support, it then without explanation a different and significantly more optimistic reduction factor for the increase in the emissions reduction achieved by increasing the frequency of the survey. Table 1 below compares the CAQCC analysis and the EPA reductions:

Table 1.

CAQCC	CAQCC	EPA	EPA
Percent Reduction	Survey Frequency	Percent Reduction	Survey Frequency
40	Annual	60	Semiannual
60	Quarterly	80	Quarterly
80	Monthly	_	_

INGAA strongly believes that survey frequency has a much smaller impact on performance than undocumented EPA source utilized by CAQCC. The credibility of EPA's estimate of how the frequency of surveys affects emissions reductions is seriously undermined by both the lack of well documented source data and the lack of explanation for the choice of even more optimistic estimates for how the frequency of surveys will affect emission reductions.

INGAA recommends that EPA should rely on a credible and well-documented study that assesses changes in LDAR effectiveness for different survey frequencies.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 123 and DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 11.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 15

Comment: In addition, EPA appears to adopt, wholesale, estimates made by the state of Colorado in support of its own 2014 rulemaking establishing a Colorado LDAR program. *Id.* (citing the Colorado Department of Public Health and Environment Air Pollution Control Division Initial and Final Economic Impact Analysis. EPA selected 80% VOC/methane emission reduction, to be expected from a quarterly frequency, 60% reductions from a semiannual frequency, and 40% reductions from an annual frequency). The Colorado estimations, however, were fraught with error, were based on simple extrapolations of exclusively annual monitoring data, and did not represent conditions actually experienced.

Colorado's estimates, which were based on inflated and inaccurate fugitive emission estimations and factors to begin with, assumed that LDAR benefits both increase with the frequency of inspection and remain constant over time. Neither of these assumptions is true. First, Colorado's estimates were based on EPA guidance that applied a "rule of thumb" assessment and did not actually conclude that benefits from an LDAR program increase with frequency or stay consistent over time. Second, the EPA guidance relied upon addressed fugitive emission reductions at chemical plants and petroleum refineries (not smaller, widely dispersed oil and gas production facilities), utilized outdated information, and employed simple averages as opposed to a more accurate distribution of components that would be expected at smaller oil and gas facilities. *See* 80 *Fed. Reg.* at 56,635 (EPA citing to a 1996 report to estimate fugitive emissions component counts). These and other errors combined to result in inaccurate estimates about the cost-effectiveness of the Colorado LDAR program and the ostensible benefits of increased monitoring frequency in particular, but EPA has relied on them without any qualification whatsoever.

Contrary to the conclusions drawn by EPA from the Colorado rulemaking, actual experience with that LDAR program at affected oil and natural gas facilities in Colorado demonstrates that: (1) following the implementation of an LDAR program, leak rate frequency found upon initial monitoring drops significantly during subsequent monitoring to less than 1 %; and (2) providing operators the flexibility to focus on high emitting and likely-to-emit components delivers the most cost-effective benefits. Experience also demonstrates that these low, post-initial-monitoring leak rates generally are sustainable over the long term. *See* Colorado Regulation. 7/Litigation Support, prepared for WPX Energy, Inc. by Trihydro Corporation, at 1-1 (January 6, 2015)

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 123 and DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 11.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 39

Comment: EPA's anticipated number of affected compressor stations is low. EPA estimated that the average number of new transmission compressor stations and new storage stations subject to any final NSPS OOOOa to be six (6) and fifteen (15), respectively. See NSPS OOOOa Technical

Support Document, at Table 5-12. Based on Kinder Morgan's experience, it appears that EPA's projected number of natural gas transmission and storage stations and associated compressor units that would become subject to the Proposed NSPS OOOOa Rule is significantly underestimated, which undermines EPA's cost analysis. First, given the increase in demand for natural gas and other factors there will be far more than six (6) new transmission compressor stations. Second, EPA's assumption that there will be twice as many storage facilities as compressor stations is nonsensical. Third, in addition to construction of new transmission compressor stations, the addition of a new compressor unit at an existing compressor station (either transmission or storage) would make that existing facility subject to the Proposed NSPS OOOOa Rule (see Section V(I), below, for further discussion regarding proposed "modification" definition). Notwithstanding, EPA failed to provide an estimate for the number of existing facilities that would become subject to the Proposed NSPS OOOOa Rule due to a modification at existing stations.

Response: The number of new transmission and storage facilities was estimated by reviewing the annual number of facilities from the year 1990 to 2012 estimated in the GHG Inventory and determining the rate of change in the number of these facilities over this period. The average change for the last 10 years was reviewed and the annual number of new transmission stations was determined to be 4 and the annual number of storage facilities was determined to be 5. This rate change also encompasses existing facilities that were modified.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 12

Comment: EPA underestimated the number of annually impacted T&S compressor stations.

EPA's projected number of transmission and storage stations and associated compressor units that would become subject to the Proposed Rule is significantly underestimated, which greatly undermines EPA's costs analysis. EPA estimated that the average number of new transmission compressor stations and new storage stations through 2020 to be six and fifteen, respectively. EPA estimated that those numbers would increase to 36 transmission and 90 storage stations by 2025. EPA's estimates were based on estimated number of facilities in the GHG Inventory for the years 1990 to 2012 and determining the rate of change in the number of these facilities over this period. INGAA's member companies operate approximately 1,000 transmission compressor stations of which only less than 300 are storage stations. Based on national transmission and storage compressor station totals, it is unrealistic to expect that the number of new storage stations would more than double the number of new and modified transmission stations annually. Moreover, the most common method for expanding pipeline system operations is to install one or more new compressor unit at an existing compressor station rather than installing new compressor stations. The installation costs to expand an existing compressor station are significantly less expensive than installing new compressor stations. EPA failed to include an estimate for the number of and associated implementation costs for existing facilities that would become subject to the Proposed Rule due to modifications at existing compressor stations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 39.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 15

Comment: EPA failed to consider secondary impacts of the monitoring and repair of fugitive emissions leaks.

The EPA failed to consider two very important issues. First, the repair of pressurized leaking components often requires depressurizing equipment and/or piping and the venting of gas. This is especially true for the Proposed Rule because EPA fails to include blowdown related delay-of-repair discretion found in other LDAR regulations. The rule should consider the volume of gas that would be released to make a repair relative to the fugitive emissions when prescribing repair requirements. For example, the rule should allow delay of repair until the next shutdown if the volume of gas released to make the repair would exceed the estimated fugitive emissions. (See discussion at Section D.)

Second, transmission stations are generally located about every 50 to 80 miles along a pipeline. This distance could be used to estimate the distance traveled to and from a site by IR camera monitoring contractors and the associated emissions. Since the proposed LDAR program includes OGI technology and repair of all leaks visualized, there will be scenarios where the leak repair will result in an inconsequential emission reduction and "secondary" emissions from transportation will eliminate the benefit.

EPA should revisit LDAR implementation cost analyses using more current data and well documented assumptions. This improved analysis should include PHMSA's existing leak regulations. Further, EPA's cost analysis should consider all of the additional costs addressed in INGAA's comments. Component repair costs at compressor stations can range from $200,000-$2.3 million when considering construction costs. There could be an additional $2.5 million in customer impact costs if the station was unable to provide natural gas to their customers.

EPA has overstated the benefits of the proposed rule by ignoring the number of blowdowns that will need to occur to fix a leak.

EPA's calculation of the anticipated benefits of the Proposed Rule fails to factor in the mechanics of fixing a leak. Operators will have to conduct blowdowns in order to fix numerous leaks at any given compressor station along the pipeline system. EPA states that it anticipates the Proposed Rule will result in a savings of 180,000 tons of methane in calendar year 2020. However, in order to fix leaks, pipeline operators have to blow down the station piping to conduct the necessary repair work. Prior to producing a net benefit calculation, EPA needs to factor in the additional releases of methane that will be required in order to address leak repairs.

INGAA offers four schematics in Appendix D that will help EPA understand the variation of impacts at a compressor station resulting from out of service events. Each schematic offers a different compressor station segment outage and the respective equipment involved. Further, the schematics offer explanations on time, costs and permitting requirements.

Response: While we believe that the secondary impacts of the NSPS are minimal, we agree with the commenter that emissions from venting were not included in the secondary impacts for the proposed rule. For the final rule, we have finalized standards that allow for delayed repair of leaking components if the repair requires a blowdown or compressor station shutdown. This alleviates the need for venting of emissions to repair a component. Therefore, venting emissions were not included in the secondary impacts. We did however, estimate the emissions occurred from driving to the facilities to conduct or repair leaking components and added these estimates to the TSD to the final rule. See DCN EPA-HQ-OAR-2010-0505-6474, Excerpt 14.

We appreciate the information provided by the commenter and have considered their comments in the re-evaluation of costs and emission reductions for the final rule for compressor stations. We also considered two other costing approaches, company owned OGI and costing based on the Colorado cost-benefit analysis. After reviewing the results, we determined that the contractor-based OGI cost approach provided a reasonable estimate of the costs of implementing and operating an OGI monitoring program.

Commenter Name: Kelly Guertin, Senior Environmental Engineer, Environmental Management and Resources
Commenter Affiliation: DTE Energy (DTE Gas Company)
Document Control Number: EPA-HQ-OAR-2010-0505-7052
Comment Excerpt Number: 10

Comment: DTE Energy supports INGAA that EPA has not acknowledged or taken into consideration existing PHMSA regulations for the timing of leak repairs. The proposed rule does not indicate that EPA has conducted any review, comparison, or reconciliation with other regulatory programs.

Response: We have reviewed information submitted by commenters and have made some revisions to the proposed rule that allows for delay of repair of leaking components if the repair would require a blowdown or compressor station shutdown. We have also added provisions for difficult to monitor components and unsafe to monitor components.

4.4 Method 21

Commenter Name: Jason Amsden, Research Scientist and Vikram Rao, Executive Director
Commenter Affiliation: Duke University Nanomaterials and Thin Films Lab and RTI International
Document Control Number: EPA-HQ-OAR-2010-0505-6240
Comment Excerpt Number: 2

Comment: We suggest that the EPA allow operators to conduct leaks monitoring surveys using either EPA Method 21 or optical gas imaging or some combination thereof. Rather than specifying a particular detection technology, we recommend that the EPA consider specifying the measurement requirements (e.g., precision, accuracy, detection threshold, response factor, etc.) and then establish a technology qualification program similar to that provided by the Transportation Security Laboratory for explosives trace detection. Such a program would enable adoption of emerging technologies such as those currently under development in the ARPA-E MONITOR program.

Response: While we agree with the importance of allowing the use of Method 21 as an alternative, we need to ensure that its use does not result in fewer emissions reductions than what would otherwise be achieved using OGI, which is the BSER based on our analysis. Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm under certain conditions. Due to the dynamic nature of OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal. Since an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm would be repaired. Method 21 is capable of detecting fugitive emissions at concentrations well below 10,000 ppm. However, if the repair threshold was set at 10,000 ppm, an owner or operator would not have to repair any leaks that are less than 10,000 ppm, thereby foregoing the reductions that would otherwise be achieved by using OGI. For the reason stated above, 10,000 ppm is not an appropriate repair threshold for Method 21.

Using information provided by commenters, we evaluated the methane and VOC emission reductions associated with the use of Method 21 at repair thresholds of 10,000 ppm and 500 ppm, the two levels recommended by the various commenters. We then calculated the emission reductions that result from using a Method 21 instrument to conduct a monitoring survey at a repair threshold of 500 ppm. This results in emission reductions greater than the emissions reductions that would be achieved if OGI were used instead.

Concerning the comment that the EPA should not specify a detection technology, we disagree. The EPA has a long history of establishing fugitive emissions (leak detection and repair) monitoring programs, such as that established in subparts VV and VVa. These rules are based on specifying the detection technology to be used. Additionally, see response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for information on a pathway for emerging technologies.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 64

Comment: Optical Gas Emissions appears to be a lower cost and more time efficient option than performing EPA Method 21. We agree that EPA Method 21 should be available as an alternative to performing OGI monitoring, but should not be required as the only option available to owners and operators. OGI and EPA Method 21 should be available for initial survey work and resurvey work also.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Clement J. Frost, Chairman
Commenter Affiliation: Southern Ute Indian Tribe Council
Document Control Number: EPA-HQ-OAR-2010-0505-6446
Comment Excerpt Number: 2

Comment: The Tribe recommends allowing both OGI and Method 21 as options for conducting leak detection at both well sites and compressor stations. The Tribe also supports the use of both OGI and Method 21 as options for conducting re-surveys for both facility types.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 10

Comment: Leak Detection and Repair (LDAR) Program - Use of Optical Gas Imaging (OGI) Technology. The EPA has proposed to require the use of OGI technology to detect leaks at oil and gas sites. The TCEQ supports the use of OGI technology, but has reservations supporting OGI as the sole compliance tool for the proposed leak detection and repair (LDAR) program. TCEQ's reservations include the limited availability and high cost of OGI instruments, and the inability to quantify leaks detected with OGI technology. In addition to the use of OGI, Method 21 should be recommended as an alternate compliance option to detect leaking components. The EPA's preamble states that OGI is generally capable of detecting fugitive emissions at a concentration of 10,000 ppmv, provided favorable wind and temperature conditions are present, and that work is ongoing to determine the lowest concentration that can be reliably detected with OGI (80 FR 56635). The EPA's proposed rule would allow companies to use OGI or Method 21 using a 500 ppmv leak definition, for resurvey and repairs of leaking components. This apparent difference in the leak detection and measurement capability of OGI, compared to the leak detection and measurement capability of Method 21, is a substantial disparity. The TCEQ has commented that the effectiveness of OGI instruments is highly dependent on the training and expertise of the operator (see enclosed Attachment 1, which contains excerpts from comments submitted on the EPA's 2011 proposal for Subpart OOOO). The EPA should gather more measurement data, further define what OGI can measure in everyday service, and provide guidance.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 19

Comment: At a minimum, EPA should amend its proposed fugitive emissions work practices to allow operators the flexibility to use Method 21 for the initial survey, and any method for resurveying under Method 21 (including soap bubbles) upon re-survey. This would provide a more "feasible" and "practicable" work practice that would still achieve the same objectives as the current Proposed NSPS OOOOa standard.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2. Concerning the use of soap bubbles, Method 21 allows a user to spray a soap solution on components that are operating under certain conditions (e.g., no continuous moving parts or no surface temperatures above the boiling point or below the freezing point of the soap solution) to determine if any soap bubbles form. If no bubbles form, the components are deemed to be operating with no detected emissions. We note that spraying soap solution to confirm whether a component has been repaired may not work for all fugitive emissions components, such as a leak found under the hood of the thief hatch since it would be difficult to apply the soap solution or observe bubbles. However, we believe that this alternative will provide some owners and operators a simple, low cost way to confirm that a fugitive emissions component has been repaired. This would also allow the resurveys to be performed by the same personnel that completed the repairs instead of other certified monitoring personnel or hired contractors that would have to come back to verify the repairs. Therefore, we are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 6

Comment: The proposal should be amended to remove the exclusion of Method 21 for LDAR initial surveys. This is a time-tested method of leak detection and there is no logical reason to eliminate it. Although EPA sets the standard, it does so without dictating a particular technology unless there is a sound scientific basis for doing so. In this case, there is not.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 19

Comment: Rather than limiting operators to only OGI or Method 21 for the survey or resurvey, Enterprise encourages EPA to craft a final rule that would allow both technologies to be used. Enterprise opposes any rule that would require the use of Method 21 and not allow for the use of OGI. We prefer OGI to Method 21 because Method 21 is slow and cumbersome, while OGI can be performed more quickly and efficiently. As EPA has noted, one study indicated that OGI can monitor 1875- 2100 components per hour, while Method 21 can only monitor about 700 components per day. As a result, limiting operators to using Method 21 would result in a much more cumbersome and inefficient final rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Ian Green
Commenter Affiliation: Benzol Group
Document Control Number: EPA-HQ-OAR-2010-0505-6815
Comment Excerpt Number: 1

Comment: This comment is being submitted to support the use of EPA Method 21 (Method 21) as an alternative to Optical Gas Imaging (OGI) for Leak Detection and Repair (LDAR) requirements within the September 18, 2015 EPA released NSPS proposal. Exclusively requiring the use of OGI technology is cost-prohibitive and OGI does not provide quantitative emissions information. The goal of reducing emissions by requiring LDAR surveys can be better achieved via Method 21; allowing Method 21 in addition to OGI will result in a higher rate of compliance being achieved with a lower cost to the industry.

To determine the cost of obtaining OGI equipment, prices were obtained from Forward Looking Infrared Gas Detection Systems (FLIR) for gas detection cameras that are currently used by the industry and state agencies to conduct OGI surveys. The models discussed had a cost between $80,000-100,000 per camera. This is an exorbitantly high cost for a leak detection system that is proposed to be the only acceptable means of compliance. While there are companies that perform OGI surveys, allowing the operator to forgo the purchase of an expensive camera, those surveys can still have a substantial cost. Conversely to the expensive OGI options, the instruments designed to detect gas leaks of various compositions via EPA Method 21 (i.e. RKI Eagle 2) cost around $1,000.00. The stated goal of these new proposed regulations is to reduce emissions of harmful air pollutants by requiring the operating community to implement LDAR programs. However, not allowing operators to utilize the proven, cost-effective EPA Method 21 adds an unnecessary financial burden on the industry and may result in a reduced rate of compliance.

In further support of the acceptance of Method 21, the GF series cameras by FLIR and other similar OGI systems are not capable of quantifying the observed emissions. According to FLIR's web page the imaging technologies capable of quantifying emissions are known as Solar Occultation Flux (SOF) and Differential Absorption Light Detection and Ranging (DIAL). SOF and DIAL are very expensive compared to the infrared technology utilized by the GF series cameras and also require large amounts of equipment to be transported via truck or trailer. As a result, SOF and DIAL are impractical technologies for the purposes of LDAR programs at oil and gas facilities. The most practical option for quantifying leaks at oil and gas facilities is to utilize a gas detection instrument designed to operate in a manner consistent with EPA Method 21. By quantifying emission leaks, operators are able to better assess and assign priority ratings to leaks and ensure that leaks are sufficiently sealed.

It is understood that a leak detection threshold must be established in order for Method 21 to be approved as an acceptable means of conducting LDAR surveys. To establish this, it is beneficial to look at Colorado's Regulations Number 7, which states that at a new facility, a leak is defined as a location where any hydrocarbon concentration exceeds 500 ppm. Please note that normal equipment operations such as crankcase venting are not subject to the 500 ppm leak detection threshold. Allowing the use of Method 21 with a 500 ppm leak detection threshold will lay the foundation for practical LDAR programs which can achieve high levels of leak reductions.

Ultimately the primary goal of the new regulatory proposal is to reduce harmful air pollutants sourced from leaking equipment. By allowing a practical, less expensive Method 21, which has the ability to also quantify emissions, operators will be able to conduct LDAR surveys and reduce emissions without incurring an unnecessary cost. A 500 ppm threshold will ensure that a large majority of the emission leaks can be detected and fixed and will be consistent for companies already complying with CO Regulation 7. It is strongly recommended that the EPA allow the use of EPA Method 21 as an acceptable alternative to Optical Gas Imaging as a cost-effective means for operators to meet this goal.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 36, 37, 51

Comment: Additionally the PBPA proposes that Method 21 be allowed for both initial surveys and resurveys to confirm repair.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 55

Comment: EPA defines fugitive emissions in such a manner as to dictate the methodology for conducting such surveys. Specifically, EPA defines "fugitive emissions" as "[a]ny visible emission from a fugitive emissions component observed using optical gas imaging." EPA confirms in the preamble discussion that it intends that all surveys be conducted using optical gas imaging, although EPA provides some opportunities for alternate methodologies upon repair and verification. EPA provides no other alternative mechanisms for completing the surveys and provides no justification for why currently accepted EPA methods, such as Method 21, or other existing and to be developed methods, are not appropriate for completing the surveys in the first instance.

EPA's limitation ignores the widespread use and current training that many in-house personnel have with the use of Method 21. Given the scope and extent of this proposed rule, operators should be afforded the greatest flexibility (both company-wide and at specific facilities) for the use of their in-house and outside resources. EPA has provided no evidence that allowing the widely utilized Method 21 as an initial methodology for survey would allow leaks to proceed unnoticed or unrepaired or result in less emissions reductions. Furthermore, EPA's proposal requires use of a qualitative methodology (OGI) in lieu of a quantitative methodology, such as Method 21. Though both methods detect leaks, operators should be allowed to use the leak threshold established by EPA and Method 21 to determine whether in fact a leak requiring repair exists. Kinder Morgan strongly recommends that where an operator identifies a leak via OGI, the operator should have the option to either (1) treat the leak as a leak and repair it; or (2) evaluate the leak with Method 21 to determine if in fact it represents a leak that requires repair. For leaks that are simple and easy to fix, a repair would be the easiest path forward and often can be completed onsite at the time of the inspection. However, in some cases, small leaks can be very difficult or expensive to repair and in absence of regulations their repair would not be justified. In many such cases, the operator may create more emissions blowing down equipment to repair a leak than would result from the delay of the leak repair.

Kinder Morgan provided additional regulatory language to reflect the use of these other methodologies both as part of the initial survey and to determine if a leak exists.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 10

Comment: The identification of "Next Generation Compliance" considerations within the context of proposed Subpart OOOOa is not appropriate.

- EPA has solicited comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring. CONSOL supports the use of EPA Method 21 as an alternative option to conduct Leak Detection and Repair (LDAR) surveys at affected facilities. EPA should not limit the options available for monitoring to operators and should also allow for future development of alternative technologies.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 5

Comment: <u>Accepted leak detection methods, including EPA Method 21, should be allowed for leak surveys</u>.

EPA's proposed LDAR program to address fugitive emissions from compressor stations would require leak detection surveys using OGI technology to the exclusion of other equivalent methodologies. EPA's proposal provides no valid justification for limiting the leak survey methodology to OGI and excluding equivalent and approved survey methodologies.

EPA's requirement that leak detection surveys be conducted using OGI technology represents a shift in the Agency's long-standing approach to using Method 21. In fact, LDAR programs in other EPA regulatory programs, including NESHAP and MACT regulations and EPA's GHGRP for oil and gas operations, allow the use of Method 21, as well as state LDAR programs.

EPA bases its BSER analysis on the use of OGI after making a determination that OGI is more cost effective than Method 21. However, many factors can influence survey costs, including, as EPA recognizes, the availability of trained OGI contractors. Yet EPA fails to take into account this cost when evaluating the cost of OGI against the cost of Method 21. As a result, EPA's determination to focus its BSER analysis on the use of OGI is flawed.

The fact that Method 21 is more cost-effective than and as equally effective as OGI is bolstered by EPA's proposal to allow the use of Method 21 for resurveys of previously identified and repaired leaks. As EPA recognizes, for repairs/replacement that cannot be made at the time the leak is discovered, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective as compared to Method 21. As such, EPA is proposing to allow the use of Method 21 for the resurvey. Allowing the use of Method 21 for these resurveys indicates that EPA is as comfortable with the level of leak detection afforded by Method 21 as it is with OGI. EPA has no valid reason for limiting the use of Method 21, or any other equivalent leak detection method for the initial leak detection survey.

The operator should have the discretion to use established methods for leak surveys, and Method 21 is the longstanding standard. The final rule should include Method 21 and the ability to implement other technologies that are proven equivalent to OGI or Method 21. If not, this program will be inconsistent with other leak mitigation programs in the U.S., as well as Subpart W leak survey methodology.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 24

Comment: The Division supports the option to survey and resurvey repaired components with EPA Method 21 and a Method 21 leak threshold of 500 ppm hydrocarbon.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 138

Comment: Allowance of EPA M21 As An Alternative to OGI

EPA solicited comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold

Proposed Subpart OOOOa implies that the initial leak surveys must be taken using an OGI [§60.5397a(c)(7)]. We recommend revising the rule to specifically state that OGI, Method 21, or an equivalent method may be used for both the initial survey [§60.5397a(c)(7)] and repair leak surveys [§60.5397a(j)(2)].

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: J. Jared Snyder
Commenter Affiliation: New York State Department of Environmental Conservation.
Document Control Number: EPA-HQ-OAR-2010-0505-6894
Comment Excerpt Number: 5

Comment: Survey Technology

EPA requested comments regarding whether Method 21 should be included in the final NSPS as an acceptable alternative to optical gas imaging (OGI) for site leakage surveys. The DEC supports the addition of Method 21 primarily because having multiple reliable approaches for detecting leaks increases flexibility and allows for comparative analyses.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 25

Comment: The proposed standards would require replacement or repair of any fugitive emissions component that has evidence of fugitive emissions detected during the survey through visible confirmation from OGI. EPA seeks comments on whether to allow EPA Method 21 as an alternative to OGI for monitoring, and on whether either OGI or Method 21 should be allowed for the resurvey of repaired components when fugitive emissions are detected with OGI.

While TPA is not opposed to the use of Method 21 as an available compliance *alternative,* we would oppose any rule that would require use of Method 21 such that use of Method 21 was the only choice available to owners and operators. In other words, OGI should always be an available alternative. Method 21 is relatively slow and cumbersome, while OGI can be performed much more quickly and efficiently. Method 21 is also more labor-intensive than OGI. Simply put, we agree with EPA that Method 21 is not as cost-effective as OGI."

Another advantage of OGI over Method 21 is that it is relatively easy to prove that a survey was performed, and when and where it was performed. As previously noted, OGI in effect acts as a video device, meaning that the proof of the survey is embedded in the survey itself. This is not the case with Method 21 technology; with a Method 21 portable detecting instrument, the operator has to document the survey with a paper trail or similar record.

Based on OGI's operational advantages and relative efficiency compared to Method 21, we urge EPA never to require use of Method 21 as a compliance tool under Subpart OOOOa, and at most to make it an available alternative to the use of OGI survey technology.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Stuart A. Clark and Ursula Nelson, Co-President
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6932
Comment Excerpt Number: 8

Comment: EPA also requested comment on whether Method 21 should be included in the final NSPS as an acceptable alternative to optical gas imaging for the site leakage surveys. NACAA supports the use of Method 21 to meet the performance standards. Many states employ Method 21 in their leakage detection programs and have noted that it allows for leakage detection at lower thresholds than optical gas imaging. Including both approaches in the final rule would give states increased flexibility and enable them to engage in a comparative analysis by deploying both techniques at the same site.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 21

Comment: USEPA Method 21 should be retained as a reference method for quantifying leaks.

While Antero does not oppose the use of an Optical Gas Imaging (OGI) camera as an initial screening tool with regard to potential emission sources, USEPA Method 21 or other appropriate technology should be the reference method for quantifying leaks. OGI camera pictures present only limited information with regard to the data generated by their use. Specifically, while the cameras can be properly calibrated and used to show evidence of potential leaks or emissions, the mere presence of visible emissions does not constitute a leak as determined by the detection methods in most NSPS or NESHAP, which may range from 500 to 10,000 parts per million (depending on the component) relative to background.

Antero submits that while an OGI camera can determine the presence or absence of fugitive emissions from components, it cannot be determinative of a "leak" as defined by a regulation that requires action on behalf of the regulated entity, because the OGI camera does not provide a quantitative value that can be compared to background to determine if a specific concentration of target constituent is being released to the atmosphere. Reliance on OGI cameras to identify "leaks" also raises safety concerns (these devices are not inherently safe as they raise the chance for fire and explosions on the site), cost concerns (the cameras are estimated to cost in excess of one hundred and twenty thousand dollars ($120,000.00) per unit plus required training/certification), consistency concerns due to interferences (heat signatures and wind effects) and the potential to subjectively misinterpret OGI images.

Accordingly, the use of OGI cameras provides no definitive evidence of noncompliance and cannot by itself be a proper tool to measure noncompliance or the existence of leaks. Qualitative measures, such as OGI cameras, should be used for an initial survey to identify potential emitters or evaluate components of the closed vent systems. Measurements using Method 21, flame ionizing devices or other technologies could then be used to assess the significance of fugitive emissions and whether a leak requiring repair exists. The post-repair condition of the repaired component having been returned to an acceptable *(de minimis)* condition would then be demonstrated using Method 21, OGI, or other appropriate technology.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 14

Comment: AGA Urges EPA To Consider Revisions That Promote Consistency With Other EPA Programs.

AGA appreciates EPA's attempt to minimize the burden on regulated parties by seeking comment on how the Agency can avoid duplication or conflicts with other existing regulations. Several examples are discussed in these comments (e.g., delay of repair provisions), and reiterated below.

Fugitive emission leak surveys should allow the use of Method 21 for consistency with EPA's Subpart W, LDAR requirements in other NSPS and NESHAPs (e.g., 40 C.F.R. Part 60 Subparts VV, VVa), as well as numerous state and local agency programs.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 17

Comment: PIOGA supports the use of EPA Method 21 to conduct LDAR surveys and encourages EPA to add Method 21 as a compliance option for the proposed rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 22

Comment: The specification of OGI technology for LDAR surveys in spite of general opposition by small business entities will only serve to enhance EPA's "NextGen Compliance" initiative at the expense of existing and effective LDAR technology currently in use.

PIOGA believes that U.S. EPA's intention to require OGI technology for affected oil and gas operations is a result of U.S. EPA's recent operational experience using such equipment in compliance related activities within the oil and gas sector. The proposed OGI requirement would put EPA's remote surveillance monitoring capabilities and intentions on a common basis with the fugitive emission requirements of proposed Subpart OOOOa. In general, PIOGA agrees that regulatory agency inspection and affected source compliance tools should be equivalent. However, as stated above, small business entities generally cannot afford to purchase OGI technology and must rely on the expertise and availability of contractors. The costs associated with semiannual LDAR surveys conducted by contractors also represent a financial burden on small entities. PIOGA believes that Subpart OOOOa should include a performance standard for the conduct of LDAR surveys with the option to use OGI or alternative equivalent LDAR technology (i.e., EPA Method 21).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Stuart A. Clark, (Washington), Co-President and Ursula Nelson, (Pima County, AZ), Co-President
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6961
Comment Excerpt Number: 8

Comment: EPA also requested comment on whether Method 21 should be included in the final NSPS as an acceptable alternative to optical gas imaging for the site leakage surveys. NACAA supports the use of Method 21 to meet the performance standards. Many states employ Method 21 in their leakage detection programs and have noted that it allows for leakage detection at lower thresholds than optical gas imaging. Including both approaches in the final rule would give states increased flexibility and enable them to engage in a comparative analysis by deploying both techniques at the same site.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Morgan Lambert, Deputy Air Pollution Control Officer
Commenter Affiliation: San Joaquin Valley Air Pollution Control District in California

Document Control Number: EPA-HQ-OAR-2010-0505-6974
Comment Excerpt Number: 4

Comment: The LDAR methods proposed in Subpart OOOOa are less effective than those in place in the District. Light oil and gas production, gas processing, crude oil refining, and heavy oil production operations are subject to the strict LDAR requirements in existing District Rules. The leak detection method required by District rules, EPA Method 21, is much more stringent than the proposed Optical Gas Imaging (OGI) method. District rules require all subject components to be inspected directly, at least annually. The allowable repair periods specified in existing District rules are also more stringent than those in the EPA proposal.

Further, District rules specify that EPA Method 21 be used for LDAR, and OGI is not an approved method. As such, if this proposed NSPS is approved, sources would have to purchase OGI equipment and train staff, or hire contractors to perform additional inspections in addition to the more stringent LDAR required by District rules.

We therefore recommend that regulation-required corporate-wide LDAR programs be allowed in lieu of OGI, and further, that EPA Method 21 be allowed in lieu of OGI in all cases.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2. See the State LDAR Comparison Memo available in the docket for this rule, at DCN EPA-HQ-OAR-2010-0505, for further discussion.

Commenter Name: Comment submitted by Todd Parfitt, Director
Commenter Affiliation: Wyoming Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2010-0505-6993
Comment Excerpt Number: 5

Comment: Including Method 21 monitoring and additional methods in FM plans

The EPA proposed optical gas imaging (OGI) as the applicable method for detecting and monitoring fugitive emissions at well sites. AQD currently accepts OGI, Method 21, and audio-visual-olfactory (AVO) as acceptable FM monitoring methods. It is important to note, however, that AQD evaluates each FM protocol on a case-by-case basis. For example, Method 21 and OGI are considered equivalent monitoring methods by AQD because each can effectively detect a small leak when properly implemented. Allowing this flexibility is important for implementation purposes because there are real-world examples where a specific method cannot be used. For example, vents, connectors, or flanges on the sides of storage vessels can be difficult to monitor using Method 21, but OGI can be used effectively from the ground. OGI may not be as effective when fugitive sources are grouped closely together in a confined area such as a separator or heater/treater building. Method 21 may work better in such situations. AQD is also aware that certain types of OGI devices are not intrinsically safe and may pose an explosion risk to operators. Allowing the use of Method 21 could mitigate the risk of an explosion.

Response: We agree that AVO monitoring in combination with OGI or Method 21 can be an acceptable form of monitoring but AVO alone is not. The final rule requires owners and operators to maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers a leak through audio, visual or olfactory means, the owner or operator has a general duty to repair these components. See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Richard S. Anderson, Director of Air Quality Compliance
Commenter Affiliation: Plains All American Pipeline, LP
Document Control Number: EPA-HQ-OAR-2010-0505-6996
Comment Excerpt Number: 2

Comment: <u>Use of Optical Gas Imaging for Fugitive Monitoring</u>. Plains appreciates the potential for cost savings that might be realized from using OGI monitoring rather than Method 21-type monitoring. However, the inability to precisely quantify leak rates for individual components, and the possibility of technological advancement in OGI technology over time raises a number of issues.

Proposed NSPS OOOOa requires the monitoring of fugitive components at compressor stations by the use of optical gas imaging (OGI) equipment, stating that any visual indication of a hydrocarbon is considered a leak. EPA states that the detection limit of OGI is approximately 10,000 ppm. This 10,000 ppm value is based on current technology and does not take into account future improvements in the technology that may occur. Indeed, the preamble goes on to state that "work is ongoing to determine the lowest concentration that can be reliably detected using OGI." A regulatory standard should not be based on a monitoring technology whose operating performance has not yet been fully explored or understood, or whose detection limits are subject to change over time.

As OGI technology improves, there could come to exist a diverse population of OGI instruments with differing detection limits, which would result in inconsistent detection and control of emissions from facility to facility. This could also result in inequitable repair costs between facilities, as some facilities would be required to replace or repair components that another facility using a less-sensitive (but still compliant) OGI instrument would not be required to repair or replace.

OGI is not a quantitative method; therefore, without further guidance from EPA, it is not be possible to calculate mass emissions based on the readings obtained from such a program, as can be done with the results of a Method 21 program. Most states require the calculation of fugitive leak emissions based on monitoring data for their annual emission inventory if a monitoring program is being utilized at the facility. Without quantitative monitoring values, this approach will be impossible with the use of OGI for fugitive monitoring and could also make it difficult to conclusively demonstrate compliance with, for example, permit limits.

Finally, EPA should retain the use of Method 21 as an option for all monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Greg Rieker, Department of Mechanical Engineering
Commenter Affiliation: University of Colorado-Boulder
Document Control Number: EPA-HQ-OAR-2010-0505-7002
Comment Excerpt Number: 2

Comment: In sections VII.G and VIII.G, comments are solicited pertaining to whether Method 21 should be allowed as an alternative to OGI in leak survey and re-surveys and for the appropriate level at which the repair threshold should be set for this method. Our opinion is that instrumentation that meets the criteria outlined for Method 21 is a viable alternative to OGI, in that it provides a means to not only identify but also quantify leaks at the individual component level.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: J. Jared Snyder, Assistant Commissioner for Air Resources, Climate Change Energy
Commenter Affiliation: New York State Department of Environmental Conservation (DEC)
Document Control Number: EPA-HQ-OAR-2010-0505-7006
Comment Excerpt Number: 7

Comment: EPA requested comments regarding whether Method 21 should be included in the final NSPS as an acceptable alternative to optical gas imaging (OGI) for site leakage surveys. The DEC supports the addition of Method 21 primarily because having multiple reliable approaches for detecting leaks increases flexibility and allows for comparative analyses.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 7

Comment: EPA Method 21 should be allowed for operators with no access to the expensive imaging programs. The same thought process of REASONABLY AVAILABLE control technology should apply to REASONABLY AVAILABLE Imaging Systems.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 46

Comment: EPA solicits comment on the option for using Method 21 as an alternative to OGI and the leak threshold that would apply. TXOGA supports a Method 21 option because there may be instances in which an owner or operator would elect to use Method 21 due to issues with OGI or other concerns.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 69

Comment: One -- one point I'd like to get in is that it's essential that the EPA 21 alternative detection procedure be retained for those producers who find it uneconomic for the camera or the sniffer or other things.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 118

Comment: There are several technologies to detect emission levels, as members are not experts in assessing the detection level of all monitoring equipment. The members do have considerable experience with EPA Method 21. And we believe it is an accurate method to determine leakage levels, especially in the lower range of what is reasonably achievable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 6

Comment: WBI Energy strongly supports allowing the use of alternative monitoring methods to OGI for conducting surveys of fugitive emission components at compressor stations. There are several accepted methods for leak detection at compressor station facilities. In Section IV. Background of the proposed rule, EPA states that "Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance." Granted, EPA is discussing emission limits in this section but WBI Energy suggests applying this same principle to monitoring. If other methods can accomplish the ultimate goal of identifying fugitive emission leaks, then it should be up to the regulated entity to determine which method works best for their facilities. Particularly, if the regulated entity already has a program in place.

In determining that OGI is the most cost effective method for conducting fugitive emission surveys, it appears the EPA only examined the number of components that can be surveyed by the equipment per hour. EPA suggests that up to three times the number of components can be surveyed by OGI versus a Method 21 instrument which lowers the cost because surveys would take less time. However, there is no discussion as to the cost of the instrument, the estimated number of components to be surveyed at a location, the ease of use and availability of the equipment, the number of facilities that could be surveyed in a day, proximity of affected facilities to one another or any other variables that could impact costs of surveys. In WBI Energy's experience, Method 21 instruments have been very reliable, cost effective and easy to use for conducting leak surveys at compressor stations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Jeff Addington, Manager Air Quality
Commenter Affiliation: Archrock Services, L. P. and Archrock Partners Operating LLC ((individually and collectively, ArchRock)
Document Control Number: EPA-HQ-OAR-2010-0505-6944
Comment Excerpt Number: 6

Comment: As to the testing itself, EPA has proposed only two options for detecting fugitive emissions from compressor stations, one of which is the use of optical gas imaging ("OGI") technology. While OGI may be a quick and viable technology for surveying leaks, it is relatively new to the industry and the equipment could be cost-prohibitive for some service providers. As to Method 21, it is time consuming. With an estimated 1,000 components per compressor, it would take approximately 4 hours to conduct a Method 21 test for a single unit. This is a large time and personnel commitment and, therefore, a significant cost.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 24

Comment: We recommend that owners or operators of the affected facilities conduct an initial survey of the collection of fugitive emissions components (e.g., valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks) using OGI technology.

Response: As discussed in our response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2, we are allowing the use of either OGI or Method 21 for conducting the initial and subsequent surveys.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 59

Comment: In regards to OGI as compared to Method 21; overall, in any given situation the technology that provides the best information is the technology that must be used.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Anonymous public comment
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6863
Comment Excerpt Number: 2

Comment: Second, I would like to respond to the effectiveness of the OGI instrument verse Method 21. This area is quite simple in our opinion. The camera gives the operator the ability to actually see where each leak is. For example, if a component is leaking an operator can tell you there is a leak in the area of the component using Method 21. With the camera, we can tell if there is two or three leaks and show exactly where they are. Using Method 21 and operator is extremely limited on the number of components they can inspect in one day, they may be able to inspect a couple of hundred components…if they move to fast they are likely to miss leaks and be accused of moving too fast. With the camera we can survey two or three thousand components in one day because the inspection is visual. Wind does not affect the OGI near as much as Method 21. Using a sniffer a component can be inspected and a leak missed if upwind from the leak. The camera will see the plume no matter where the wind is coming from. With all of that being said, that also makes OGI a less expensive inspection method because we can move much faster and be more thorough in our inspections. Also, if a source is leaking on the location that is not on the list of components to be inspected, the OGI operator will likely identify it in the course of the survey.

Response: The EPA appreciates the commenter's insights. As discussed in our response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2, we are allowing the owner or operator to choose between OGI and Method 21 for conducting the surveys.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 11

Comment: Organic vapor analyzers should be allowed and encouraged instead of FLIR cameras only.

Response: As discussed in our response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2, we are allowing the owner or operator to choose between OGI and Method 21 for conducting the surveys..

Commenter Name: Camilla Feibelman
Commenter Affiliation: Rio Grande Chapter of the Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-6895
Comment Excerpt Number: 9

Comment: We also believe requiring use of the best equipment (such as gas infrared cameras) for both initial surveys and re-surveys could help reduce substantially methane and co-pollutant emissions from leaking equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Mark Boccella, Americas Business Development Manager, Optical Gas Imaging
Commenter Affiliation: FLIR Systems, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-7063
Comment Excerpt Number: 4

Comment:

VII.G.1	Fugitive Emissions from Oil and Natural Gas Production Well Sites
Pg. 106	We solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold
VII.G.2	Fugitive Emissions from Compressor Stations
Pg. 112	We solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold

The efficiency of OGI technology is tied to its unique ability to help operators visualize leaks and directly see their source. Due to this fact, the adverse effects of wind (direction and speed) on the emissions plume are less extensive as compared to other approved technologies. Figure 1 below demonstrates a common example where a Method 21 approved device (TVA) is not able to identify a laboratory produced methane leak when wind direction diverts the plume away from the instrument probe. **[Note: Figure 1 (Lab testing shows adverse effects of wind direction on probe-type TVA instrument)]**

Alternatively, the plume is easily detectible with OGI technology since the entire surrounding area is being passively monitored. This of course allows for the operator to actually see the source of the leak, preventing repair errors and eliminating false positives where blowing emissions are present at surrounding components. This concept also lends to the realization that LDAR programs utilizing OGI are considerably more efficient, as the technology allows operators to scan hundreds of components simultaneously. This of course is a critical parameter to consider when scaling up frequent inspections in a cost-effective way.

Additionally, OGI technology has been proven to be more effective at locating leaks in confined spaces and hard to reach areas, reducing the need for scaffolding and man-lifts. Since many components at a well site or compressor station are physically difficult to reach and/or require an operator to be put in harm's way when accessing, an imaging technology has an inherent benefit over probe type instruments that must be submerged within the emissions plume. The Mandatory Reporting of Greenhouse Gases Rule (75 FR 74458) in its inception accurately identified this principal via the following verbiage:

An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface...EPA still requires the use of optical imaging cameras to reach inaccessible emission sources where the reporter cannot use Method 21 compliant leak detection equipment safely.

In summary, we believe that the minimal adverse effects of wind, increased inspection efficiency, and inaccessibility of common components support the agency's adoption of OGI as the Best System of Emissions Reduction (BSER) for reducing fugitive methane and VOC emissions at well sites and compressor stations.

Response: The EPA appreciates the commenter's insights. As discussed in our response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2, we are allowing the owner or operator to choose between OGI and Method 21 for conducting the surveys.

Commenter Name: Roy Rusty Bennett
Commenter Affiliation: Mehoopany Creek Watershed
Document Control Number: EPA-HQ-OAR-2010-0505-6816
Comment Excerpt Number: 3

Comment: Because well sites and compressor stations are located near our homes and schools, we want to see the most accurate methods of survey technology utilized every time.

In regards to surveys, we recommend the EPA structures technology preferences based on how to obtain the best information in any given emission situation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 22

Comment: Leak Detection Methods Other than OGI Should Be Allowed.

The Proposed Rule requires Optical Gas Imaging (OGI) for leak detection, and EPA solicits comment on whether additional methods should be allowed. INGAA strongly supports including flexibility for leak detection, and EPA Method 21 should be in included as an option for leak surveys. In the preamble, EPA concludes that OGI is more cost effective than Method 21, but many factors can influence survey costs – including the availability of trained operators and OGI instruments, which are orders of magnitude more costly than Method 21 instrumentation. The operator should have the discretion to use other established methods for leak surveys, such as Method 21. The final rule should include Method 21 and the ability to implement other future EPA-approved technologies that are proven as equivalent to OGI or Method 21. If not, this program will be inconsistent with every other leak mitigation program in the U.S., as well as the Subpart W leak survey methodology.

EPA's Proposed Rule contains a leak survey method requiring the more restrictive OGI technology. However, EPA's Subpart W requirement allows either OGI or Method 21. EPA should strive for consistency with existing programs to avoid similar, duplicative efforts. Since a primary objective of the GHG Reporting Program was to inform policy decisions, EPA should better utilize data and information available from Subpart W reporting and reconsider environmental benefits and the need for regulation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 7

Comment: Repair thresholds should be based on no bubbling at leak interface when using soap solution, no detectable image using OGI technology or concentrations at leak interface less than 10,000 ppm relative to background.

Response: In the final rule, the leak definition is 500 ppm when using Method 21. Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm under certain conditions. Due to the dynamic nature of OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal. Since an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm would need to be repaired. Method 21 is capable of detecting fugitive emissions at concentrations well below 10,000 ppm. However, if the repair threshold was set at 10,000 ppm, an owner or operator would not have to repair any leaks that are less than 10,000 ppm, thereby foregoing the reductions that would otherwise be achieved by using OGI. For the reason stated above, 10,000 ppm is not an appropriate repair threshold for Method 21. See section VI.F.1.c and VI.F.2.b of the final rule preamble for more detail regarding this issue. Also see the Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program Memo, available in the docket for this final rule at EPA-HQ-OAR-2010-0505, for further discussion.

Concerning the use of a soap solution, Section 8.3.3 of Method 21 allows a user to spray a soap solution on components that are operating under certain conditions to determine if any soap bubbles form. We are finalizing the use of these alternate screening methods for resurveying repaired components. See section VI.F.1.e and VI.F.2.d of the final rule preamble for more detail regarding this issue.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 20

Comment: Regardless of the survey method that EPA ultimately selects, it is important the EPA set an appropriate threshold level of emissions for survey or resurvey of repaired components, so that operators are not required to perform time consuming and costly repairs on tiny leaks that have no meaningful impact on the environment. This threshold is important to making sure that this rule functions as EPA intends. Because the proposed NSPS does not distinguish between smaller and bigger leaks, operators must treat all leaks alike, and address them all on the same timeline. A threshold lower than 10,000 ppm will only force operators to spend more time chasing small leaks that are not environmentally impactful, and will distract operators from handling true compliance concerns as quickly as possible. As a result, Enterprise proposes that 10,000 ppm is an appropriate threshold for leak detection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 23

Comment: The Leak Threshold for Method 21 Surveys Should Be 10,000 ppm.

EPA solicits comment on the appropriate leak definition concentration if Method 21 is included in the final rule. As noted in the preamble, current NSPS include thresholds ranging from 500 to 10,000 ppm. It is important to understand that these thresholds were established for VOC regulations, where the measured stream may include constituents other than hydrocarbons. When nonhydrocarbon species are within the stream, the measured concentration is diluted to lower values. For the natural gas sector, typically ninety percent or more of the stream is methane and nearly the entire stream is hydrocarbon. Thus, relative to a diluted VOC stream, a smaller leak of natural gas will record a higher hydrocarbon concentration. In addition, for T&S the Proposed Rule is primarily interested in reducing methane emissions – rather than VOCs or Hazardous Air Pollutants (HAPs). Very small leaks that may be detected with a low concentration threshold (e.g., 500 ppm) are not likely to provide meaningful reductions when GHG impacts are the primary environmental concern.

Since existing NSPS with lower concentrations thresholds are associated with VOC regulations and different process streams, a higher threshold is appropriate for a regulation addressing methane leaks. INGAA recommends a leak definition concentration of 10,000 ppm. This is consistent with the range of thresholds in current regulations, also consistent with the OGI performance objectives in § 60.5397a(c)(7)(i)(B), and consistent with the Subpart W leak definition.

Response: We disagree with the commenter. This rule regulates both VOC and methane emissions and seeks to get meaningful emission reductions from both. See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association

Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 6

Comment: The leak definition should be 10,000 ppm when using Method 21 for leak detection.

AGA appreciates EPA's recognition that Method 21 is an accepted leak detection practice and the Agency's solicitation of comment on the appropriate leak definition concentration if Method 21 is included in the final rule. AGA believes that a leak definition of 10,000 ppm is consistent with the range of thresholds in current regulations, including the Subpart W leak definition, as well as with EPA's proposed OGI performance objectives.

In its proposal, EPA notes that current NSPS include thresholds that range from 500 to 10,000 ppm. However, thresholds lower than 10,000 ppm were established for VOC regulations, where the measured stream may include constituents other than hydrocarbons. When nonhydrocarbon species are within the stream, the measured concentration is diluted to lower values and a lower leak detection threshold is necessary. For natural gas, ninety percent or more of the stream is methane and nearly the entire stream is hydrocarbon. Thus, compared to a diluted VOC stream, a smaller natural gas leak will record a higher hydrocarbon concentration. Because EPA's proposed standard for T&S is primarily interested in reducing methane emissions—rather than VOCs or HAPs, the leak detection concentration should be set so that leaks that are a significant source of methane are targeted. Repair of very small leaks detected with a low concentration threshold (e.g., 500 ppm) is not likely to provide meaningful reductions when GHG impacts are the primary environmental concern. This is the consistent with EPA's GHGRP Subpart W leak definition, which is 10,000 ppm when using Method 21. In addition, since existing NSPS with lower concentrations thresholds are associated with VOC or HAP regulations, a higher threshold is appropriate for a regulation addressing methane leaks – particularly downstream of processing where there are virtually no VOCs remaining in the natural gas.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 24

Comment: In the Preamble, USEPA solicits comment on whether the fugitive emissions repair threshold should be set at 10,000 ppm above background

A leak rate of 10,000 ppm has been the standard threshold in most LDAR programs established in the states and has been the backbone of many federal NSPS (Subparts VV, VVa, GGG, and KKK) and NESHAP (Subparts H, UU, and TT) programs. Antero suggests that the fugitive emissions repair threshold should be set at a level that is high enough to warrant repair such as 10,000 ppm above background or higher.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 8

Comment: The leak definition should be 10,000 ppm when using Method 21 for leak detection.

AGA appreciates EPA's recognition that Method 21 is an accepted leak detection practice and the Agency's solicitation of comment on the appropriate leak definition concentration if Method 21 is included in the final rule. AGA believes that a leak definition of 10,000 ppm is consistent with the range of thresholds in current regulations, including the Subpart W leak definition, as well as with EPA's proposed OGI performance objectives.

In its proposal, EPA notes that current NSPS include thresholds that range from 500 to 10,000 ppm. However, thresholds lower than 10,000 ppm were established for VOC regulations, where the measured stream may include constituents other than hydrocarbons. When nonhydrocarbon species are within the stream, the measured concentration is diluted to lower values and a lower leak detection threshold is necessary. For natural gas, ninety percent or more of the stream is methane and nearly the entire stream is hydrocarbon. Thus, compared to a diluted VOC stream, a smaller natural gas leak will record a higher hydrocarbon concentration. Because EPA's proposed standard for T&S is primarily interested in reducing methane emissions—rather than VOCs or HAPs, the leak detection concentration should be set so that leaks that are a significant source of methane are targeted. Repair of very small leaks detected with a low concentration threshold (e.g., 500 ppm) is not likely to provide meaningful reductions when GHG impacts are the primary environmental concern. This is the consistent with EPA's GHGRP Subpart W leak definition, which is 10,000 ppm when using Method 21. In addition, since existing NSPS with lower concentrations thresholds are associated with VOC or HAP regulations, a higher threshold is appropriate for a regulation addressing methane leaks – particularly downstream of processing where there are virtually no VOCs remaining in the natural gas.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 23

Comment: AGA Urges EPA To Consider Revisions That Promote Consistency With Other EPA Programs.

AGA appreciates EPA's attempt to minimize the burden on regulated parties by seeking comment on how the Agency can avoid duplication or conflicts with other existing regulations. Several examples are discussed in these comments (e.g., delay of repair provisions), and reiterated below.

For Method 21 leak surveys, the leak definition should be 10,000 ppm for consistency with LDAR requirements in other existing regulations, including EPA's GHGRP.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 8

Comment: Additionally, WBI Energy recommends that when using Method 21, a leak should be defined as 10,000 ppm to be consistent with 40 CFR 98.234.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: J. Roger Kelley, Director, Regulatory Affairs
Commenter Affiliation: Continental Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6963
Comment Excerpt Number: 12

Comment: Establish a Numerical Value to Define a Leaking Component.

In line with the above comment regarding flexibility in LDAR technology selection, a numerical leak threshold value should be established for operators who opt to use a Method 21 (PID) approach either for LDAR inspections or for repair verification. Continental believes that based on the existing NSPS for equipment leaks from onshore natural gas processing plants (i.e., NSPS KKK) a numerical leak threshold of 10,000 ppm would be consistent with the proposed 60.5397a(c)(7)(i)(B) OGI performance requirement.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 47

Comment: The lower detection threshold of OGI and the Method 21 leak thresholds should be 10,000 ppm.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 9

Comment: The Division supports the option to survey and resurvey repaired components with EPA Method 21 and a Method 21 leak threshold of 500 ppm hydrocarbon. EPA has proposed to allow the resurvey of repaired fugitive emissions components using either EPA Method 21 or OGI, for repairs that cannot be made during the monitoring survey when the fugitive emissions are found.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 7.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 13

Comment: In Addition to OGI Monitoring, EPA Should Require Annual Method 21 Monitoring with a 500-ppm Repair Threshold

Method 21 monitoring is an effective tool to identify leaks when there is not a clear line of sight to the fugitive component or there is a low level leak. Relying on OGI exclusively for fugitive emission detection could cause significant leaks to go undetected. For example, using an OGI "from ground level can miss leaks" from elevated sources. Method 21 devices require operators to get within the vicinity of the suspected leaking source and are less likely to be subject to similar "parallax" type errors. Additionally, using method 21 with a 500 ppm threshold can help detect lower levels. The contractors we spoke with recommend that a robust fugitive detection program would adopt the use of both technologies because both have different strengths and weaknesses.

Response: Using information provided by commenters, we evaluated the methane and VOC emission reductions associated with the use of Method 21 at repair thresholds of 10,000 ppm and 500 ppm, the two levels recommended by the various commenters. We then calculated the emission reductions that result from using a Method 21 instrument to conduct a monitoring survey at a repair threshold of 500 ppm. This results in emission reductions greater than the emissions reductions that would be achieved if OGI were used instead. For the reasons stated above, using Method 21 to conduct monitoring surveys at a repair threshold of 500 ppm is better than, or at least equivalent to using OGI to conduct the same survey; we are therefore allowing it in the final rule as an alternative to the use of OGI. We do acknowledge that the cost of conducting a survey using Method 21 may be more expensive than using OGI; however, some owners or operators may still chose to use Method 21 for convenience or due to the lack of availability of OGI instruments or trained personnel. Also see the Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program Memo available in the docket for this final rule, at EPA-HQ-OAR-2010-0505, for further discussion.

Commenter Name: Greg Rieker, Department of Mechanical Engineering
Commenter Affiliation: University of Colorado-Boulder
Document Control Number: EPA-HQ-OAR-2010-0505-7002
Comment Excerpt Number: 4

Comment: As for the appropriate repair threshold associated with Method 21, we believe the level should be the same level at which a repaired leak re-surveyed with Method 21 is considered repaired, e.g. 500 ppm in the proposed rule. If a leak is not considered repaired until after component emissions register less than 500 ppm, it follows that a leak detected during an initial survey at a concentration greater than 500 ppm should be repaired. We believe this threshold should be chosen so that the requirements between Method 21 and OGI are similar (so that industry does not purposely choose the less stringent path). For example the assumed level of emissions identified through visual detection with OGI is nominally 10,000 ppm. However, as outlined in the next paragraph, we believe the leak repair threshold for methane should be based on leak rate, as opposed to concentration.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6953, Excerpt 13.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 52

Comment: EPA also requests comment as to whether or not Method 21 should be allowed as an alternative to OGI to conduct the initial inspections and if so, what the appropriate threshold should be to define a leak. 80 Fed. Reg. at 56,612. We believe OGI is generally superior to Method 21, due to its efficacy in scanning entire facilities for leaks and directly locating leaks. If EPA decides to allow Method 21 for initial inspections, 500 ppm would be the appropriate threshold to define a leak, consistent with the leak threshold for gas processing plants from NSPS Subpart OOOO. Given the advantages of OGI, its low cost, and the availability of service providers to perform OGI (relieving small operators of the need to purchase equipment, for example), EPA should also consider approaches that would encourage OGI, such are requiring that one inspection per year be carried out with OGI.

Response: Our analysis for the proposed rule found OGI to be more cost-effective at detecting fugitive emissions than Method 21, and we identified OGI as the BSER for monitoring fugitive emissions at well sites and compressor stations. We received comments expressed by small entities that indicated a concern with needing to purchase an OGI instrument or hire trained OGI contractors to perform their monitoring surveys. Based on interest in having Method 21 as an approved alternative, we have finalized Method 21 as an alternative to OGI for monitoring fugitive emissions components at a repair threshold of an instrument reading of 500 ppm or greater. We are also finalizing specific recordkeeping and reporting requirements when Method 21 is used to perform a monitoring survey. For more information see section IV.F.1.c of the preamble to the final rule.

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 2

Comment: Use of Method 21 or OGI for recheck after repair (pages 107 and 114)-Our Company does not offer method 21 testing as a core service, however, we recognize the merits of the use of Method 21. Method 21 or OGI should both be allowed for retest after repair.

Response: In the final rule, the EPA is allowing the use of OGI or Method 21 for monitoring and resurveying repaired components. Components must be repaired if emissions are visualized using OGI or at a concentration of 500 ppm or higher when Method 21 is used. Components are deemed "repaired" if no emissions are visualized using OGI or there are no detectable emissions (less than 500 ppm above background) when Method 21 is used. See section VI.F.1.c and section VI.F.2.b of the final rule preamble for more information regarding this issue.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 11

Comment: The TCEQ has suggested requiring a Method 21 test for resurveying leaks detected by an OGI instrument rather than require an annual Method 21 on all components screened with the Alternate Work Practice. Another option the EPA could consider is leak-skip options for the annual Method 21 monitoring.

Response: We proposed a performance based monitoring frequency schedule but we received overwhelming comments requesting that we finalize a fixed schedule. See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Dr. Anish Goyal, Vice President, Technology
Commenter Affiliation: Block Engineering
Document Control Number: EPA-HQ-OAR-2010-0505-6213
Comment Excerpt Number: 4

Comment: We believe that OGI is not suitable for the re-testing of repaired components because of the following reasons.

1. OGI has a high limit of detection (i.e., low sensitivity). According to the proposed rule, the estimated limit of detection using OGI is about 10,000 ppm (or about 1%). Method 21, on the other hand, may be performed with thresholds as low as 500 ppm. Furthermore, Method 21 requires the instrument scale to be ±2.5% of the specified leak definition concentration such that the instrument sensitivity could be as low as 12.5 ppm. This sensitivity is almost 1000-times better than with OGI.
2. OGI is an infrared imaging technology whose sensitivity depends upon several factors including the following:
3. The inherent variability in sensitivity of the system to environmental temperatures and wind speed (see below) means that day-to-day (or even hour-to-hour) consistency of measurements cannot be maintained.
4. OGI infers the product of the concentration and path-length (i.e., CL-product) of the gas cloud that results from the leak. It does not directly measure the gas concentration.
5. The inferred concentrations are extremely sensitive to wind speed which affects the local gas concentration as well as the size of the gas cloud that is caused by the leak. Both of these directly affect the CL-product and, therefore, the sensitivity of the system. Even for substantial leaks in the presence of wind, the CL-product could be small and escape detection by OGI.
6. The inferred concentrations with OGI are also extremely dependent upon the temperature difference between the gas and the background objects behind the leak within the line-of-sight of the OGI instrument. Under conditions where the gas and the background objects are at the same temperature, the sensitivity of OGI will be severely degraded. As a result, OGI is generally not suitable for measuring leaks indoors where it is more likely that the gas temperature to be similar to that of background objects. Furthermore, the sensitivity of OGI will depend upon viewing direction since this will also change the optical properties of the background objects.
7. OGI typically operates in a wavelength range where many of the gases of interest have overlapping spectral signatures. Therefore, it is not suitable for distinguishing among the various kinds of hazardous air pollutants (HAPs) such as volatile organic compounds (VOCs) and methane.

Once a leak has been detected, and the component has been repaired, it is expected that the leak rate from that component will be reduced. If re-testing of the leaking component is performed using OGI, then the quality of the repair will not be measurable using OGI. For example, if a leak is just above the threshold for measurement using OGI and the component is just marginally repaired, it may pass the test according to OGI. However, such a borderline leak has the potential to grow into a much larger leak during the interval between surveys. Method 21, however, provides a much higher sensitivity measurement and it can be used to determine whether the repair was performed properly.

According to EPA's proposed rule, the cost of using Method 21 is estimated to be $2 per component. Therefore, we do not see that a significant cost burden is placed on operators by requiring that repaired components be tested using Method 21.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Henri Azibert, Technical Director
Commenter Affiliation: Fluid Sealing Association (FSA)
Document Control Number: EPA-HQ-OAR-2010-0505-6754
Comment Excerpt Number: 8

Comment: In response to the solicitation for comments in the last paragraph of page 106 and continuing on page 107, or similar questions posed in several other places, we would like that the following be considered. While we have less experience with it, we note that OGI technology can be utilized to find leaks. All the equipment can be used to identify larger leaks, or collective leaks, which are responsible for significant emissions. Some of the more sensitive devices can also detect smaller leakage incidences. Once offending components have been located, the use of EPA Method 21 can document the leakage level and can then be used to verify the effectiveness of the repair. Since personnel is on site for the repair, the use of method 21 is not onerous at this point. Sealing devices manufacturers have had a significant and successful role in helping their customers in their goal of quantifying and then reducing emissions. Documentation of leakage levels is essential to maintenance programs in order to determine their effectiveness. Programs that are geared toward reducing fugitive emission to their lowest levels also insure the reduction of the incidence of massive leaks as more effective technologies are used.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 14

Comment: QEP supports allowing OGI and Method 21 technologies for the resurvey of repaired components when fugitive emissions are first detected with OGI. QEP thanks EPA for the additional flexibility.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 8

Comment: Methods of Surveying: EPA should give operators the flexibility to use Method 21, or any equivalent method, upon re-survey to confirm leak repair. Many factors can influence survey costs, and EPA does not justify why other, currently accepted methods, are inappropriate for completing such surveys.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 25

Comment: The Division supports the option to survey and resurvey repaired components with EPA Method 21 and a Method 21 leak threshold of 500 ppm hydrocarbon. EPA has proposed to allow the resurvey of repaired fugitive emissions components using either EPA Method 21 or OGI, for repairs that cannot be made during the monitoring survey when the fugitive emissions are found.

Colorado's regulations allows the monitoring of components with EPA Method 21, and establish a 500 ppm leak threshold. However, Colorado's regulation specifies 500 ppm of hydrocarbon, in contrast to EPA's 500 ppm above background. The Division notes that EPA's 500 ppm above background will produce variable inspection, and thus repair, results due to the potential differences in each facility's "background." The Division, therefore, suggests EPA establish a 500 ppm pollutant specific leak threshold. The Division also supports the option to conduct the fugitive emissions components survey with EPA Method 21, or specifying that a source may alternatively comply with Colorado's LDAR program. As discussed in Colorado's economic impact analyses, which EPA cites in the proposed NSPS OOOOa preamble and TSD, Colorado found the use of EPA Method 21 and the 500 ppm hydrocarbon leak threshold to be cost-effective (see Final economic analysis, pgs. 14-27).

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 133

Comment: API Supports Flexibility In The Methods Allowed For Resurveying Repaired Components.

EPA solicited comments on whether either optical gas imaging or M21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. API supports flexibility in the methods allowed for resurveying repaired components. EPA should allow for the use of M21, OGI, or infrared laser beam illuminated instruments. In particular, M21 is preferred, as Section 8.3.3 of M21 allows the use of soap bubbles for leak detection, which currently does not appear to be allowed per §60.5397a (j)(2)(i).

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2. Concerning the use of a soap solution, Section 8.3.3 of Method 21 allows a user to spray a soap solution on components that are operating under certain conditions to determine if any soap bubbles form. We are aware of the multiple technologies listed (i.e., tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas leak detectors; and remote methane leak detectors). The technologies listed are generally too costly, cannot be universally applied due to technical limitations (e.g., necessity for hard target), represent incomplete solutions for fugitive emissions management (e.g., action levels for path averaged concentrations with varying path lengths), or lacking the supporting documentation (e.g., equivalence with proposed OGI, fugitive emission systems expected emission reductions). While we are not taking action on allowing these as the BSER or as an alternative, we encourage the continuing development of leak detection systems in this sector. We are finalizing the use of these alternate screening methods (soap solution) for resurveying repaired components. See section VI.F.1.e and VI.F.2.d of the final rule preamble for more detail regarding this issue.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 23

Comment: USEPA Method 21 should be retained as an option for the reference method for the resurvey of the repaired components

As discussed above, Antero supports the use of USEPA Method 21 as the quantitative approach to verifying if a leak exists and whether a repair has addressed a leaking component. Qualitative measures, such as OGI cameras, should be used for an initial survey to identify potential emitters, if any. Measurements using a quantitative method should be used to assess the significance of a leak and, if repairs are warranted, the post-repair condition demonstrating that the component has been returned to an acceptable *(de minimis)* condition.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 32

Comment: PIOGA supports the use of Method 21 for resurveys that cannot be performed during the initial monitoring survey and repair.

The use of Method 21 is consistent with existing LDAR requirements in Pennsylvania.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 53

Comment: EPA also requests comment as to the appropriate approach—OGI or Method 21—operators should use to re-survey repaired components, and if Method 21 is allowed, whether or not 500 ppm is an appropriate threshold to require to verify a repair. 80 Fed. Reg. at 56,612. We note that most state LDAR programs allow operators the flexibility to use either of these approaches, with the same frequency, as well as other approved instrument monitoring, and we support this flexible approach.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Mark Boccella, Americas Business Development Manager, Optical Gas Imaging
Commenter Affiliation: FLIR Systems, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-7063
Comment Excerpt Number: 5

Comment:

VII.G.1	Fugitive Emissions from Oil and Natural Gas Production Well Sites
Pg. 107	We solicit comment on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI
VII.6.2	Fugitive Emissions from Compressor Stations
Pg. 113	We solicit comment on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI

As the EPA adopts a resurvey standard moving forward, we believe it is reasonable to allow operators to choose the approved inspection method that fits best within their devised program. To this point, it is relevant to reference the US EPA's Alternative Work Practice, (71 FR 17401) which was codified in 2008 allowing facilities to identify leaking equipment using an OGI instrument in addition to an approved leak monitor referenced in 40 CFR part 60, Appendix A-7 (i.e., a Method 21 instrument). While this practice was novel in concept, the Alternative Work Practice (AWP) still required an annual inspection using Method 21 equipment. Since this eliminated any potential for a reduction in overall program cost, we believe this requirement forced a large majority of operators to forego the adoption of the AWP, thereby lowering the effectiveness of their leak detection programs.

A recent series of case studies performed by Target Emission Services illustrated that removing the annual Method 21 requirement from the Alternative Work Practice (AWP) would result in 57% cost savings to the facility operator. OGI performed at a higher frequently is still more cost effective than Method 21, and allows operators to find the big leaks early and often. When employing the AWP during the referenced case studies, over 90% of the volume of emissions measured can be attributed to the use of OGI, whereas less than 10% (volume) were detected by Method 21 during the annual requirement. We believe this demonstrates that OGI provides an improvement in overall emissions control and is considerably less burdensome to implement as compared to Method 21, where it can be challenging to manage inventory via tagging protocols.

Response: We thank the commenter for the information regarding the Alternative Work Practice (40 CFR 60, subpart A). See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 28

Comment: We would like that not to be tied to a percentage of leaks, and we'd like to have resurveys done with the same technology that found the leak.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 14

Comment: EPA Must Require Operators to Resurvey Repaired Equipment Using Method 21 at a 500-ppm Detection Threshold

Where an operator detects fugitive emissions using OGI or Method 21 and conducts a repair, EPA must require operators to use Method 21 to resurvey the repaired components.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 27

Comment: If necessary, EPA could allow a limited exception to this requirement to allow facilities to resurvey repaired equipment using OGI if the equipment is unsafe or otherwise not possible to monitor using Method 21. Otherwise, Commenters urge EPA to require Method 21 at a 500-ppm threshold for all resurveys of repaired equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 19

Comment: Fugitive Emissions From Oil and Natural Gas Production Well Sites

When appropriate, we recommend that OGI should be allowed for the resurvey of the repaired components. There are operators that have this technology and the ones that don't need to plan to add it to their tool kit. Utilizing the best available technologies applicable to the situation at hand is more protective of public health and safety. With an increasing amount of sites and fugitive emissions near our homes and schools it is imperative that the best technologies be appropriately employed in order to assure that both inspections and repairs are effectively completed.

2. Fugitive Emissions From Compressor Stations

We recommend that OGI should be allowed for the resurvey of the repaired components. There are operators that have this technology and the ones that don't need to plan to add it to their tool kit. Utilizing the best available technologies is more protective of public health and safety. With an increasing amount of sites and fugitive emissions near our homes and schools it is imperative that the best technologies be employed in order to assure that both inspections and repairs are effectively completed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 9

Comment: Operators Are Already Using This Leak-Detection Technology

Operators in the oil and gas industry are already using OGI technology to detect fugitive emissions and likely already own the necessary equipment. Leading gas-producing states such as Pennsylvania and Ohio require operators to perform OGI leak surveys on a quarterly basis as part of their fugitive control programs. Further, many companies are already using OGI equipment on a voluntary basis because the technology is cost effective for reducing emissions and recovering saleable product. One company in particular is conducting inspections of 150 central distribution facilities monthly and surveys of wellheads annually. Additionally, an independent contractor has provided the agency with information, submitted separately as confidential business information, demonstrating that he has been conducting surveys for major oil and gas companies for five years and several of his clients have recently purchased the equipment and are conducting the surveys with in-house employees.

The widespread adoption of quarterly OGI monitoring demonstrates that it is cost-effective. Furthermore, EPA's proposal requiring industry to perform OGI surveys is not an additional new financial burden, but instead part of normal business expenses for the oil and gas industry and should not be considered as part of the cost of implementing the proposed work practice standard.

Response: The BSER determination must also take into account "the amount of air pollution" and "technological innovation." Based on the analysis of the OGI monitoring frequencies, we believe that semiannual OGI monitoring for well sites and quarterly OGI monitoring for compressor stations meets these requirements for BSER and have included these requirements in the final rule. Please see final rule preamble section VI.F.1.a and VI.F.2.a for further additional discussion. Also see the TSD to the final rule for more information on the costs and emission reductions for the finalized well site and compressor stations monitoring frequencies.

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 3

Comment: Regarding what the appropriate leak level should be when using Method 21, we agree with the EPA suggested 500 ppmv threshold for non-leaking.

Response: In the final rule, the EPA is allowing the use of OGI or Method 21 at a leak definition of 500 ppm for resurveying repaired components. See section VI.F.1.c and section VI.F.2.b of the final rule preamble for more information regarding this issue.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 11

Comment: The identification of "Next Generation Compliance" considerations within the context of proposed Subpart OOOOa is not appropriate."

- The Pennsylvania Department of Environmental Protection (PADEP), has implemented an effective means of addressing fugitive VOCs and methane emissions from oil and gas production operations. Through the use of Exemption 38, PADEP has required operators of new "unconventional" gas wells to institute a fugitive VOC and methane monitoring program. The program includes requirements for initial and annual LDAR surveys using either optical gas imaging (OGI) methods such as the forward looking infrared (FLIR) camera or alternative methods including EPA Method 21. The program includes provisions for prompt repairs to leaking components with a 500 ppm repair criteria.
- CONSOL supports the proposed use of 500 ppm above background as the appropriate repair resurvey threshold when Method 21 instruments are used. The use of 500 ppm above background is consistent with existing LDAR requirements in Pennsylvania.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 33

Comment: PIOGA supports the proposed use of 500 ppm above background as the appropriate repair resurvey threshold when Method 21 instruments are used.

The use of 500 ppm above background is consistent with existing LDAR requirements in Pennsylvania.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 28

Comment: OGI monitoring has a minimum detection threshold of 10,000 ppm, which is far too high a threshold to detect the emissions of individual repaired components. As a result, components deemed as repaired based on an OGI resurvey could actually continue to emit VOCs and methane with a concentration of up to 10,000 ppm. Over time, such continued fugitive emissions could add up to a significant quantity of VOCs and methane. To prevent the possibility of faulty repairs and continuing fugitive emissions, EPA must revise the provision and require operators to resurvey repaired components using Method 21 at a 500-ppm threshold. Such a protocol will help assure that leaks are actually repaired.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 106

Comment: Consistent with our comments above, if operators use Method 21, 500 ppm is the appropriate threshold for determining whether a leak has been repaired." This is the threshold required by the Colorado rules for components at new and existing well sites and at new compressor stations. 5 Colo. Code Regs. § 1001-9 XVII.F.6. It is also the threshold Utah requires for well sites authorized under its General Permit.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 7

Comment: As specified in § 60.5397a G) (2) (ii) (A) of EPA's proposed NSPS, "a fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background." However, the proposed provision does not indicate whether the less than 500 ppm standard should be expressed as VOC, Methane, or total hydrocarbon emissions. The DEP recommends that EPA clarify in the final rule, which pollutant (methane, VOCs, or total hydrocarbons) must be less than 500 ppm above background.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Henri Azibert, Technical Director
Commenter Affiliation: Fluid Sealing Association (FSA)
Document Control Number: EPA-HQ-OAR-2010-0505-6754
Comment Excerpt Number: 9

Comment: Three emission levels have been listed and questions have been posed as to their reasonableness. They are 500 ppm, 2,500 ppm and 10,000 ppm. They apply to surveys (pages 285/286) and to the appropriate fugitive emissions repair threshold (pages 259/260). In the case of valves, (listed as a fugitive emission component, p. 574), it is the opinion of the FSA members that the leakage level that is reasonably achievable from the stem seal is less than 100 ppmv. This is significantly lower than the listed levels, but follows established standards and industry practices, such as prescribed in API standards 622 and 624, that specify allowable emission levels from what is considered a low emission valve (containing methane or VOCs). This emission level is current practice in facilities using LDAR programs in refineries and chemical plants. This level of emission performance should be the standard practice for any new or repaired valve that is used in methane or VOC service.

And for flanges, (also listed as a fugitive emission component, p. 574), the reasonably achievable leakage level is even lower than for valve stems. Although there are many variations in the type and size of flanges, it is generally recognized by FSA members that a level of 50 ppmv or lower is reasonably achievable and, absent any special circumstances, it should never exceed 100 ppmv.

For this reason we support the use of lower allowable emission levels for valves and flanges than the ones proposed. Fugitive emission levels tend to increase over time in failing components. A medium level leak is one that will eventually turn into a massive leak if not attended to. Furthermore, the cumulative impact of small leakage levels results in high release of harmful gases to the environment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 231

Comment: Three emission levels have been listed and questions have been posed as to their reasonableness. There are 500, 2,500 and 10,000 ppm. In the case of valves, it is the opinion of FSA members that leakage level is reasonably achievable from the set seal is less than 100 ppm. And for flanges, the reasonable achievable leakage level is even lower than for valve stems. Although, there are many variations of types and size of valves, it is generally recognized that a level of 50 ppm or lower is reasonably achievable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 33

Comment: We believe that EPA should follow their definition of a Leak for EPA Method 21, as reported on Page 12 of their Leak Detection and Repair – A Best Practices Guide publication. EPA's publication states, "Method 21 requires VOC emissions from regulated components to be measured in parts per million (ppm). A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Most NSPS have a leak definition of 10,000 ppm." Using EPA's definition will enable our industry to identify and cost effectively repair leaks at our facilities. If EPA implements a threshold of 500 ppm, two different definitions of a leak would result in a conflict in EPA's documentation. The lower limit may also result in additional maintenance and documentation costs to address the additional leak points that would substantially impact our business.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 15

Comment: EPA Must Provide a Reasonable Method 21 Repair Resurvey Threshold

However, QEP objects to the 500 ppm repair resurvey threshold for Method 21. In the proposed NSPS OOOOa, EPA assumes a 10,000 ppm leak detection threshold for OGI. See 80 Fed. Reg. at 56635 (providing "recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation provided that the right operating conditions (e.g., wind speed and background temperature) are present"). NSPS OOOOa also provides, "[f]or purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging." ld. at 56667. Although without precise quantification, OGI can detect emissions to about 10,000 ppm; yet the resurvey using Method 21 requires repairs to a 500 ppm leak threshold.

QEP urges EPA to revise the Method 21 resurvey repair threshold to 10,000 ppm to maintain consistency between the two methods and avoid a scenario where emissions are not detected via the OGI (because they are less than 10,000 ppm) but they are detected using Method 21. The difference in emissions between a 500 ppm leak and a 10,000 ppm leak is de minimis; so maintaining this consistency would not compromise the program's environmental benefits. By identifying the same 10,000 ppm leak detection and repair resurvey thresholds, EPA will also be applying consistent precedent to OOOOa that was set in the detection and repair resurvey thresholds for previous NSPS equipment leak standards. See, for example, NSPS Subpart VV (Standards for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry), 40 CFR §§ 60.482-2(b)(1); 60,482-7(b); 60.482-8(b) (providing a leak detection threshold of 10,000 ppm for certain pumps, valves, pressure relief devices and connectors and identifying a "repaired" leak in § 60.281 as when "equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§60.482-2(b)(2)(ii) and (d)(6)(ii) and (iii), 60.482-3(f), and 60.482-10(f)(1)(ii), is remonitored as specified in §60.485(b) to verify that emissions from the equipment are below the applicable leak definition"). See also NSPS Subpart KKK (Equipment Leaks of VOC from Onshore Natural Gas Processing Plants) (requiring compliance with NSPS VV, 40 CFR §§ 60.482-2 through 60.482-10). 40CFR § 60.632(a).

Accordingly, QEP requests EPA revise 40 CFR § 60.5397a(j)(2)(ii)(A) by adding the bold words to provide that:

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than **10,000 ppm** above background.

With specific regard to EPA's CTG, QEP reiterates the comment above and requests that EPA recommend a 10,000 ppm leak detection and resurvey repair threshold (for both OGI and

Method 21) to states required to establish RACT for equipment leaks from well sites and in future implementation efforts and rule-makings.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 19

Comment: Third, GPA urges EPA to revise the fugitive emissions threshold for remonitoring actions using Method 21. As proposed, EPA would require emissions from a repaired component to be less than 500 ppm above background when tested using Method 21. Proposed 40 C.F.R. § 60.5397a(j)(2)(ii)(A). This requirement for Method 21 is not analogous to OGI detection limits. Under field conditions, OGI can consistently detect leaks at 10,000 ppm. 80 Fed. Reg. at 56,635. This is the same as the Method 21 leak detection limit imposed by EPA for fugitive emissions in 40 CFR Part 60 subparts KKK and VV. By proposing that leaks be repaired at an effective definition of 10,000 ppm with OGI or 500 ppm with Method 21, EPA would create a strong incentive for operators to use OGI rather than Method 21 for remonitoring. It is inappropriate for EPA to promote a particular leak detection methodology over another after concluding that both are suitable for remonitoring. By using a leak definition of 10,000 ppm for both methodologies, neither Method 21 nor OGI would have an advantage over the other technology. GPA urges EPA to level the playing field for remonitoring by revising the leak detection limit in 40 C.F.R. § 60.5397a(j)(2)(ii)(A) to 10,000 ppm.

Moreover, incorporating inconsistent emission thresholds for repaired fugitive emissions components will create confusion and uncertainty if the same component is tested using different methods. For example, under EPA's proposal, a leaking component that is retested after repair using Method 21 would require additional repair work if emissions were determined to be between 500 and 1,000 ppm. However, after a second repair, the same component could be tested again using OGI. Under those circumstances, it would be impossible to determine whether the second repair was successful because the component's emissions would have been below the OGI detection limit, even before the second repair was attempted. EPA should remove such uncertainty by providing uniform fugitive emissions threshold under both methods.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 27

Comment: USEPA solicits comment whether 500 parts per million (ppm) above background is the appropriate repair resurvey threshold when Method 21 instruments are used or if not, what the appropriate repair resurvey threshold is for Method 21.

A leak threshold of 500 ppm above background concentration is not an appropriate leak threshold. Antero recommends that a leak threshold of 10,000 ppm above background is appropriate for all fugitive emissions components subject to LDAR. A single uniform threshold will be easier to implement than different thresholds for different component types. It is Antero's experience that a small percentage of components are typically responsible for leaks. In addition, the Control Techniques Guideline document (Page 9-33) states that "The use of a monitoring plan using Method 21 with a 10,000 ppm leak detection may, however, be a lower cost alternative to OGI where there are fewer equipment components to be monitored."

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 2.

Commenter Name: J. Roger Kelley, Director, Regulatory Affairs
Commenter Affiliation: Continental Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6963
Comment Excerpt Number: 20

Comment: To the contrary, EPA's requirement of "no detectable emissions" (based on the 500 ppm numerical threshold) during either periodic compliance inspections or repair verifications would be logically inconsistent with its contention that OGI technology is most suitable for oil and gas LDAR programs.

Response: Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm when restricting its use during certain environmental conditions such as high wind speeds. OGI can also image emissions at a lower concentration when environmental conditions are ideal. Because an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm, would be repaired. Method 21 is capable of detecting fugitive emissions at concentrations well below 10,000 ppm. However, if the repair threshold was set at 10,000 ppm, an owner or operator would not have to repair any leaks that are less than 10,000 ppm, thereby foregoing the reductions that would otherwise be achieved by using the OGI. For this reason, 10,000 ppm is not an appropriate repair threshold for Method 21 and 500 ppm was chosen as the repair threshold. See also section VI.F.1.c of the final rule preamble for more information.

4.5 Other Detection Technologies

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 25

Comment: An alternate methodology to the prescribed LDAR program to mitigate fugitive emissions from upstream oil and gas operations would be a Directed Inspection and Maintenance (DI&M) program, allowing each operator to determine where inspections should take place based on its unique, intimate knowledge of its operating assets. DI&M is a well-established and EPA-recognized tool for detecting, prioritizing, and repairing fugitive emissions in a cost-effective manner. It provides operators with the flexibility to utilize the knowledge of their operations to identify the major leaks, which historically have been found to emanate from a small number of sources.

We recommend that each new facility undergo a methane leak detection survey within the first 90 days of production with immediate repairs effected within 15 working days of identification. Once the initial survey is completed, unless the operator has specific knowledge to indicate otherwise, it should be assumed that the facility is not likely to develop significant fugitive emissions leaks for the next several years and recurrent surveys should not be required. Operators should be given the freedom to select the sites which should be surveyed based upon their knowledge of the operations and the propensity for particular components to develop significant fugitive emissions leaks. The operator would then resurvey approximately 20% of its affected facilities each year so that each facility is re-surveyed once every 5 years, or upon major modification to the facility. Based upon industry experience with DI&M programs within the midstream, transmission, and distribution sectors, we anticipate that associated costs will be significantly lower than the proposed LDAR program surveys and reporting required under this section.

Response: The EPA disagrees with the commenter's statement that a facility is unlikely to develop significant fugitive leaks for several years after an initial survey and repairs are completed. Fugitive emissions are often caused by a failure of a seal, gasket, valve packing, or other mechanical component. Such failures could occur at any time and have little relationship to previous fugitive emissions monitoring surveys. Therefore, we are finalizing requirements for the initial survey to be conducted 60 days of the startup of production or by one year after the date of publication of the final rule in the Federal Register, whichever is later. Subsequent surveys must be conducted at least semiannually for well sites and quarterly for compressor stations. Regarding DI&M programs, please see DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)

Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 8

Comment: INGAA's DI&M program is more consistent with EPA's statutory requirements for establishing a work practice standard than LDAR. In the case of fugitive methane emission components at compressor stations, EPA is acting under §111(h) of the Clean Air Act (CAA), which provides authority to EPA to promulgate a particular work practice standard only if that standard reflects "the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated)." section 111(h) also authorizes EPA to permit the use of an "alternative means of emission limitation" if EPA finds that it will achieve a reduction in emissions "at least equivalent to the reduction" achieved by the designated work practice.

As explained in detail above, INGAA's DI&M program is a cost-effective and abundantly demonstrated technique that achieves substantial emission reductions in fugitive methane emissions at compressor stations. The LDAR program in the Proposed Rule, by contrast, imposes substantially higher costs and higher risks to "energy requirements" – with no meaningful gain in emissions mitigation. Therefore, if EPA appropriately fulfills its statutory obligation to "take into consideration" costs and impacts on energy requirements, it should eliminate LDAR in favor of DI&M. At a minimum, DI&M should be permitted as an "alternative means of emission limitation."

For these reasons, INGAA urges EPA either to: (1) determine that DI&M, not LDAR, is the work practice standard for fugitive methane emissions at compressor stations; or (2) permit the use of DI&M as an "alternative means of emission limitation" pursuant to CAA §111(h)(3).

Response: The EPA disagrees with the commenter that we should use a DI&M program instead of the proposed fugitive emissions monitoring program. In the TSD to the proposed rule and the TSD to the final rule, both of which are available in the docket, the EPA demonstrated that the fugitive emissions monitoring and repair program is BSER, which includes an analysis of costs and impacts. Therefore, we are continuing to require fugitive emissions monitoring and repair programs in the final rule, although the program requirements have been amended since proposal. See section VI.F of the preamble to the final rule for more information regarding this issue.

Additionally, we note that we have added a procedure at §60.5398a of the final rule for owners or operators of affected facilities to apply to the Administrator for a determination of whether an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §60.5397a. Such an alternate means may include corporate fugitive emissions monitoring programs that deviate from the requirements of §60.5397a. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name/Affiliation: Robert L. Stout, Jr., Vice President and Head of Regulatory Affairs / BP America, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6941 / Excerpt Number: 2, 3, 4

Comment: The Need for Regulatory Flexibility Permitting Rapid Adoption of New, More Efficient, and Cost-Effective Methane Leak Detection and Repair Technologies as They Become Commercially Available

As EPA is aware, these LDAR requirements are not flexible and will be very costly and labor-intensive to implement. Application of conventional LDAR approaches to onshore natural gas production wells is particularly difficult, cumbersome and expensive. Unlike refineries or other plant environments where LDAR requirements have more traditionally been applied, the proposed rule would now mandate the testing of literally tens of thousands of well components at many thousands of wells, widely dispersed and often located at remote sites across thousands of miles. Costs include the up-front investment in OGI cameras and related equipment but, even more significantly, the training of staff in the proper operation of the equipment (to avoid the false negatives and positives that can easily occur) and the implementation of the program across the wide span of natural gas production sites. The time and resources required to conduct this monitoring will be significant and the training and recordkeeping burdens will be substantial, as will the enforcement burden to the Agency.

With the dramatic scale-up of LDAR activities under EPA's Proposed Rule, there are strong incentives to develop technologies that can bring down costs and conserve resources while maintaining and even enhancing leak detection effectiveness. We believe these technologies not only have the potential to benefit the regulated community, but can offer a more efficient and effective way of pinpointing and fixing leaks to achieve the widely shared goal of mitigating the most significant sources of methane emissions.

Mindful of these considerations, the Agency has asked for comment on "criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining."

EPA is also "requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future."

In response and as these requests demonstrate, while periodic surveys of oil and gas well pads using OGI may represent today's technology for methane leak detection, rapid development of new technologies with different and better detection capability may soon make possible less costly, more efficient LDAR programs that achieve equal or greater methane emission reductions. We applaud EPA for recognizing the potential benefits of emerging technologies and seeking to stay abreast of work underway within and outside government to bring these technologies to fruition.

So that these technologies can be quickly deployed, EPA should build into its final rule an "on-ramp" mechanism for rapid introduction of new detection equipment and monitoring strategies once they are validated and shown to be effective. This should include a streamlined, fast-track review process, with firm deadlines for decision-making written into the rule, assuring that alternatives to the current LDAR requirements can be approved without time-consuming amendments to the NSPS or other potentially complex and cumbersome processes that could inhibit the rapid development and deployment of such technologies.

To support assessment of alternative LDAR strategies, we urge EPA to stay abreast of technological developments and closely track the results of research and testing through an open dialogue with experts in the private sector and government. Consideration should be given to formation of a technical review committee open to all interested parties for this purpose.

Ongoing Research and Development Activities

The demand for improvements in monitoring technology and methods is already stimulating a substantial increase in R&D investment, as EPA notes in its proposal. We call to the Agency's attention two ongoing initiatives that aim to develop improved LDAR technologies for use by companies as they seek to comply with methane emissions reduction requirements: a public-private initiative and a partnership between a number of corporate actors and an environmental non-governmental organization. These initiatives appear to hold considerable promise in demonstrating, within the next few years, and potentially even sooner, the commercial availability of substitute technologies, equipment and approaches that are (i) more efficient and cost-effective than the OGI-based survey approach mandated in the proposed rule and (ii) will lead to methane reductions that are at least as great or greater.

Department of Energy (DOE)/ Advanced Research Projects Agency - Energy (ARPA-E)

As of December 16, 2014, ARPA-E had selected eleven private sector projects involving methane observation networks with innovative technologies to obtain methane emissions reductions to receive awards totaling some $35,000,000 (MONITOR Program). The objective is to catalyze and support the development of transformational, high-impact energy technologies that can effectively promote methane emissions reduction. As the Agency is aware, ARPA-E has been in regular communication with EPA regarding the MONITOR Program including throughout the inter-agency process leading up to public release of the Proposed Rule.

DOE's aim is to lower the cost of compliance through the development of low- cost detection systems coupled with advanced modeling capabilities to pinpoint major leaks and then prioritize mitigation, with a focus on larger emitters. The Proposed Rule's approach, consistent with current technology, relies on detection alone as the criterion to define the need for repair, without any prioritization based on the size of the leak. Generally the thrust of the work being supported by ARPA-E is to develop technologies that allow for examination of larger areas, continuous in some instances, to identify significant leaks which can then be specifically identified and repaired.

ARPA-E is planning within 6-7 months to set up a facility where technologies will be tested in a standardized, realistic environment outside of the laboratory. This would be followed by a second round of testing to assess previously undemonstrated capabilities and further technical gains. ARPA-E believes some of these technologies could become commercially available within 2-3 years. The goal is to demonstrate one or more technologies that do not require the manpower, fleets of trucks and other equipment and surveys necessary for component-by-component LDAR using OGI. This would greatly reduce the time and manpower required for compliance, a cost driver that dwarfs the costs of acquiring an expensive FLIR camera ($90,000). Each of ARPA-E's partners will need to demonstrate it can bring the costs down to $3,000 per site per year (many of which have multiple wells). The hope and expectation is that costs will be significantly lower and perhaps as small as $1,000 per site.

EDF Methane "Detectors Challenge" (MDC)

In June, 2014, the Environmental Defense Fund (EDF) along with five corporate partners, issued a request for a proposal aimed at innovators from universities, start-up companies, instrumentation firms, and diversified technology companies with the capability to develop continuous methane leak detection monitoring for the oil and gas industry. They also sought expressions of interest in becoming part of the lab and field tests that would lead to pilot purchases and testing at oil and gas facilities. The MDC is intended to catalyze and expedite development and commercialization of low-cost, methane detection technologies that will improve methane emission reduction in the oil and gas industry. MDC is based upon the belief that shifting the methane emission detection paradigm from periodic to continuous will allow leaks to be found and fixed, more readily decreasing methane emissions significantly. The ideal system would serve as a "smart" alarm sending an alert to an operator when an increase in ambient methane is detected that reflects emissions beyond what one would normally expect to see. The MDC identifies cost as a critically important factor and EDF and its partners have sought out technologies that could reasonably be expected to be sold for roughly $1,000 or less per well pad (or compressor site) when produced at scale over the following 2-5 years.

The MDC commenced with a set of laboratory tests of five different sensor technologies in 2014, called "Phase 1". Four of these five technologies were selected for further development and assessment in a follow-up effort referred to as "Phase 2", which tested each technology developer's entire system in controlled laboratory and outdoor settings in order to ensure that the systems performed as required. The primary objective of Phase 2 was to determine the readiness of technologies for pilot testing in the field and to identify continuous improvement opportunities. A major focus was whether the systems could detect leaks in a dynamic environment with minimal false alarms and little or no maintenance or user interaction. With the completion of Phase 2, the best performing technologies will proceed to an industry purchase and trial deployment phase, which will determine whether the technologies are ready for commercial deployment.

Creating an On-Ramp for Alternative Monitoring Equipment and Strategies

Under the LDAR strategies described in §60.5397a of EPA's Proposed Rule, leaks are to be detected through periodic monitoring surveys, beginning 30 days after well completion and repeated semi-annually or at longer or shorter intervals depending on the monitoring results. These surveys must "observe" each component capable of fugitive emissions using OGI, based on a "defined walking path" that "must ensure that all fugitive emissions components are within sight of the path."

This paradigm - which requires direct manual inspection and measurement of all well site components with leakage potential at specified intervals using hand-held detection equipment-could be replaced by an entirely new approach if some of the technologies under development are demonstrated and validated.

For example, the focus of the EDF's Methane Detectors Challenge, discussed above, is "shifting the methane emission detection paradigm from periodic to continuous." This might be achieved through a sensor device installed at a single location or series of locations that, as described by EDF, "will serve as a 'smart' alarm, sending an alert to the operator when an increase in ambient methane is detected." The detection could occur at any time, not during a periodic survey. It would result in direct follow-up at the general location where methane was detected, including use of OGI to pinpoint the leak and then manual repair of the leak. However, the time-consuming manual observation of every component necessary during a survey would no longer be required, greatly reducing cost and manpower. At the same time, continuous automatic monitoring would enable significant leaks to be detected that would not be found until a periodic survey is conducted and hence would shorten the time between occurrence of a leak and its detection and repair.

It would be unfortunate if deployment of these new strategies were blocked or inhibited by the more prescriptive LDAR requirements in EPA's rule. To avoid this and to create a path toward rapid acceptance of new LDAR strategies, we propose that the rule establish a streamlined, fast-track process for approving new detection technology and monitoring methods that can be easily substituted for the OGI-based survey protocol in EPA's Proposed Rule. Where a new technology has been adequately field tested and validated through the ARPA-E MONITOR, EDF MDC or other programs and meets performance specifications outlined by EPA, the rule should authorize its deployment following a review by the Agency that should not exceed 180 days from submission of a complete data package by the technology developer or an oil or gas company. This firm deadline should be included in the rule itself to assure expedited action so the same or higher methane emissions reductions can be realized while the cost of doing so is reduced.

A potential precedent for this approach is the guidance issued by the Colorado Air Pollution Control Division (CAPCD) under AOCC Regulation No. 7, the state's LDAR requirements for methane and other pollutants emitted during oil and gas production. The regulation lays the groundwork for approving alternative technologies by defining "approved instrument monitoring method" (AIMM) as an infra-red camera, EPA Reference Method 21 or "other Division approved instrument based monitoring device or method." The implementing guidance then outlines minimum criteria for approval of such a device or method, including:
• whether it has "repeatable proven or demonstrated success in the field for hydrocarbon leak detection;"
• "its leak detection capability and reliability;"
• "how leaks and venting events are tracked and recorded;"

• "how effective it is under different types of weather conditions;"
• the "proven lower detection limit of the AIMM;"
• the ideal and maximum "distance for the lower detection limit;" and
• whether the AIMM is "capable of identifying specific leak/vent locations... or only within a general area."

Under the guidance, the CAPCD will review applications on a quarterly basis and issue an approval letter after the applicant conducts a field test attended by Agency staff and the adequacy of the technology has been verified.

EPA should include in its rule an approval mechanism for alternative monitoring equipment and methods patterned closely on the Colorado approach and incorporating similar approval criteria. Once equipment and methods have been approved for use at oil and gas well sites, all companies should be free to deploy them or to continue to implement the OGI-based approach in the rule.

Importantly, there should not be a requirement to demonstrate that alternative monitoring equipment is "equivalent" in performance to Method 21 or OGI on a component-by-component basis. This demonstration could require extensive data and create obstacles to approval. Instead, the focus of the approval process should be on overall leak detection effectiveness, as determined by considerations of leak detection capability and reliability and successful deployment in the field.

We would like to discuss with EPA, in support of timely review and approval of new technologies, mechanisms through which the final NSPS rule could periodically take account of new LDAR technologies as these become commercially available. We think the Agency and the industry should reap any cost-saving and other benefits from the ARPA-E MONITOR and EDF MDC programs, and from other efforts, as these begin to yield an array of validated and field tested new sensing technologies and revised monitoring protocols after the final rule is promulgated. Reviews of existing technology would help to assess the capabilities and reliability of new sensing devices and related changes in the procedures and schedule for leak identification and repair. The Agency has a chance to write a more flexible rule that can achieve equal or greater methane emissions reductions at significantly lower cost.

There are precedents for building into final emission control regulations "look back" mechanisms to assess whether changes in technology warrant alternative approaches to complying with rule provisions. A leading example is EPA's light- duty vehicle greenhouse gas emission standards for MY 2018-2025. The goal of that technology review is to determine whether the MY 2022-2025 emission limits in the rule are feasible given the pace of technology development since the rule was promulgated. The timetable and process for the technology review are formalized in the rule itself (§ 86.1818-12(h)).

Response: The EPA thanks the commenter for the provided information. We are aware that there is a rapidly growing push to develop and produce low-cost monitoring technologies to find methane and VOC emissions sooner and at lower levels than current technology allows, thus enhancing the ability of operators to detect fugitive emissions at well sites and compressor stations. We agree that continued development of these cost effective technologies is important and that the final rule should accommodate it to the extent possible, and we are keeping abreast of the progress being made in this area. We encourage the continuing development of leak detection systems in this sector and the efforts to provide the EPA and operators viable robust cost effective continuous monitoring for fugitive emissions. Many of these monitoring technologies are still in the development or prototype phase, and as such, specific information needed to assess the viability of these technologies, such as detection capabilities, operating parameters, monitor uptime when exposed to real world situations and costs, is not yet available for BSER analysis or to help construct a flexible system. While we agree that the ideal flexible system would be to provide performance based methodology and/or performance specifications with initial testing and on-site certification and on-going QA procedures along with the necessary ancillary recordkeeping and reporting, the emerging technologies represent a wide range of monitoring approaches such as drone, mobile, continuous, periodic, etc., and we do not have enough information to propose or finalize such requirements. We are also mindful of our obligation to ensure that monitoring technologies meet established standards that ensure accurate and precise measurement and recording of data. Therefore, these emerging technologies could not be considered BSER or as approved alternatives for this final rule. We note that review of the standard and technology basis of the standard is required every 8 years, at which time we could update the rule to include technologies that have matured and have the appropriate information to support them.

Because we believe that it is important to allow for the adoption of new technologies where appropriate, in the final rule, we have finalized a pathway for an owner or operator to apply for an alternative means for emission limitation (AMEL) for a fugitive emissions monitoring and repair program that owners or operators believe is equivalent to the final rule's fugitive emissions monitoring program. An example of an AMEL would be the use of a monitoring technology that is not specified in the rule or OGI instruments that cannot meet the specific requirements in the rule, such as an OGI instrument that is unable to visualize propane as the indicator for VOC. An AMEL application would not need to demonstrate that the technology is equivalent to OGI or Method 21 on a component-by-component basis, but must demonstrate that the emissions reductions achieved with the new technology is equivalent to or better than the emissions reductions achieved by the work practice standard (i.e., the fugitive emissions monitoring program specified in §60.5397a). We note that an AMEL is not the same as an alternative monitoring request because an AMEL is an alternative to a work practice standard. The EPA does not delegate the authority for alternative means of emission limitations approvals in order to ensure nationally consistent implementation.

To facilitate the application and review process, the final rule outlines information to be provided in the application. This information will be needed for us to evaluate the emerging technology. Such information must include a description of the emerging technology and the associated monitoring instrument or measurement technology; a description of the method and data quality used to ensure the effectiveness of the technology; a description of the method detection limit of the technology and the action level at which fugitive emissions would be detected; a description of the quality assurance and control measures employed by the technology; field data that verify the feasibility and detection capabilities of the technology; and any restrictions for using the technology. Different elements may need to be included in the monitoring plan and other recordkeeping and reporting requirements may be needed for new technologies, but this information can only be determined once we have information on the technology.

We note that the AMEL application is subject to a public notice and comment period. While we have not written specific timelines for approval of AMEL applications into the final rule, the EPA is committed to reviewing applications as expeditiously as possible. We encourage owners and operators to informally consult with the EPA before and during the preparation of an AMEL application for emerging technology in order to streamline the approval process. We intend to make a final determination on AMEL applications within six months after the close of the public comment period after noticing a complete AMEL application. See sections VI.F.1.i and VI.F.2.i of the preamble to the final rule for further discussion on this topic.

Commenter Name: P. DeMarco
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5167
Comment Excerpt Number: 13

Comment: Require advanced technologies to control fugitive emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 139

Comment: Proposed Text Revisions Related To Testing and Monitoring Requirements

§60.5397a(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging, methods listed under 60.5397a(h), or approved alternative detection device under paragraph (m) of this section.

§60.5397a(j)(2)(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using ~~either Method 21 or optical gas imaging~~ one of the methods specified in §60.5397a(h) within 15 days of ~~finding such~~ repairing the fugitive emissions~~s~~ source.

Add new proposed §60.5397a(h) below and re-letter paragraphs (h) through (l) to (i) to (m) to accommodate this addition:

§60.5397a(h). The initial and subsequent monitoring surveys specified in paragraphs (f) and (g) of this section must be conducted using one of the following methods:

(1) Optical gas imaging equipment.

(2) Method 21 (including soap bubbles as specified in Method 21, Section 8.3.3).

(3) A method that the company keeps records to demonstrate that is equivalent in detecting leaks to either of the methods specified in paragraphs (h)(1) or (h)(2) of this section.

(4) Screening methods, including but not limited to Tunable Diode Laser Absorption Spectroscopy (TDLAS), Interference Polarization Spectrometer (IR-CIPS), or Differential Absorption Light Detection and Ranging (DIAL LiDAR) technology, that screen for no leaks. If these methods do not detect a leak, then that survey is considered to have identified no leaks. However, if a leak is identified by one of these screening methods, then a monitoring method specified in paragraph (h)(1), (h)(2), or (h)(3) of this section must be used to confirm the presence of the leak.

Add:

(m) Alternative detection devices that can meet the following criteria can be submitted for approval for use by the Administrator or delegated authority within 180 days of a complete submittal:

(1) Occurs at least annually

(2) Pinpoints the general location of the leak

(3) Is capable of detecting the hydrocarbons found at the site

(4) Testing and certification are repeatable

(5) Information on the limitations, other applications, how the devices works, how it will be used, and the process for recordkeeping and training are provided.

Response: The EPA appreciates the commenter's suggestions. While we are not adopting the commenter's suggested rule language, we are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. Additionally, see response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: J. Jared Snyder
Commenter Affiliation: New York State Department of Environmental Conservation.
Document Control Number: EPA-HQ-OAR-2010-0505-6894
Comment Excerpt Number: 13

Comment: Furthermore, the DEC recommends that EPA account for new and improving technology by defining a placeholder in the regulation which would allow for the approval of new leak detection technologies with an expedited approval process. The DEC has utilized this type of language in a number of its area source rules with success.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 9

Comment: WBI recommends that the monitoring plan focus on how the instrumental monitoring of the fugitive emission components is to be completed and allow for alternative methods to OGI for conducting the monitoring as stated above.

Response: In the final rule we are making allowances for the use of OGI and M21. We have tailored the monitoring plan requirements to include information that will ensure that these technologies are used in a way that effectively monitors fugitive emissions. Because we do not know what other technologies or leak detection approaches may be used in the future, we cannot specify what information is appropriate to include in the monitoring plan at this time. However, we note that the request to use alternative technologies will include the type of information necessary to make this decision, and that information will likely be included in any approval that we issue.

See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 12

Comment: Again, page 107, "we are proposing to allow the use of either Method 21 or OGI for resurveys." Again, this excludes a wide variety of proven fugitive detection technologies that are out on the market.

Page 109, "the monitoring plan must also include a description of how OGI surveys will be conducted that ensures fugitive emissions can be imaged effectively." Again, this assumes the use of a single technology and excludes a wide variety of proven fugitive detection technologies.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 13

Comment: Page 111, "we have identified OGI technology with semiannual survey monitoring as the BSER," which means best system for emission reduction, "for detecting fugitive emissions from new and modified well sites." The BSER analysis in the proposal does not include a large number of available technologies for fugitive emission detection. Rather, it seemed to compare Method 21 technologies versus OGI. The study is not complete. We believe it's inaccurate.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 10

Comment: EPA Should Ensure a Pathway for Technologic Innovation. OGI is emerging as robust technology for identifying leaks from components in the upstream oil and gas industry. However, Noble understands that significant research is occurring in both private and public institutions to develop better, less costly technologies for identifying leaks. Noble strongly encourages EPA to incorporate in the final version of subpart OOOOa a pathway for innovation that permits researchers or vendors to submit to EPA proposals for new technologies, along with a streamlined method for authorizing the use of new technologies. For example, OGI technologies cannot be used to measure leaks, while a separate technology is capable of measuring leaks but is less cost-effective than OGI technologies. Noble is hopeful that a private or public institutions will develop a technology that enables both functions.

Remote monitoring technologies also hold significant promise. Another potential emerging technology initiative is the Methane Detectors Challenge that has been spearheaded by the Environmental Defense Fund, in collaboration with a number of oil and gas exploration and production companies, including Noble. EPA is one of the advisors to that effort. The purpose of the Challenge is to bring to market low-cost, continuous methane emission detection systems that could be used throughout the value chain. These sensors show great promise for detecting leaks at a range of distances from potential sources. It is vitally important that EPA not limit the opportunities for use or installation of new technologies in this rapidly developing field.

In addition, Noble encourages EPA to consider ways in which its own Methane Challenge initiative could become a vehicle for stimulating research and development of new technologies for detecting and measuring fugitive emissions in a safe and cost-effective way. While it does not appear that EPA has considered the option of using the Methane Challenge as a mechanism for spurring innovation, Noble believes this is one way in which companies could participate in the Methane Challenge.

Section 111 (a)(1) of the Clean Air Act provides that a "standard of performance" means a standard that reflects the degree of emissions limitation achievable through the best system of emission reduction (BSER) the Administrator determines has been adequately demonstrated. In another context, EPA has broadly defined the term "system." This provision of the Act can be read in concert with section 111 (b)((5), which discourages the Administrator from requiring the use of any particular technological system of continuous emission reductions.

Viewing these provisions in tandem, Noble respectfully suggests that EPA could replace the proposal's reliance on OGI and Method 21 with a provision that authorizes any technological system that yields equivalent emissions management at a comparable or lower cost. (Colorado's regulations provide an example of how states can create a streamlined approach for authorizing new leak detection technologies.) In the alternative, EPA also could identify the BSER as any technology that has the capacity to consistently and accurately determine if a component is leaking, and could also establish a streamlined process for authorizing such technologies.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 9

Comment: The current Subpart OOOOa proposal does not provide a pathway for utilizing new technologies thereby stifling innovation of new technologies and potentially limiting the ability of operators to minimize impacts from leaks. Anadarko recommends that agencies not limit the advancement of technologies through regulations that prescribe specific technologies. The current proposed Subpart OOOOa requirements limit LDAR programs to OGI or Method 21 surveys. Currently, there are many initiatives to develop new technologies to detect methane from oil and natural gas facilities.

This flexibility could be in the form of a simple process and authority for delegated states to approve "alternative monitoring." The current proposed regulation would inhibit the use of new technologies, since approval processes can take years. This simple approval process would provide greater environmental benefits and motivate the industry to strive for more efficient and effective monitoring strategies.

Solution: Anadarko recommends that EPA modify the existing Subpart OOOOa to include authority for delegated state agencies to approve the use of alternative monitoring technologies and practices from what is prescribed in the regulation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Jonas Kron
Commenter Affiliation: Trillium Asset Management, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6794
Comment Excerpt Number: 4

Comment: Technology for real time identification of large leaks is being developed now and will allow for enhanced deployment of cameras, quicker repairs, and larger emission reductions. For that reason, Trillium believes the final regulation should support and incentivize innovation in leak detection technologies and practices. This signal to the market from the EPA is an important opportunity to keep development of methane detection technology stalled at its current state.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 18

Comment: Enterprise encourages EPA to adopt a final rule that would allow operators additional flexibility in selecting methods to detect meaningful leaks at compressor stations. As previously noted, many of the larger leaks that EPA should be most concerned with can be detected with auditory or visual inspections. In addition, the new technologies may be developed that could more accurately and efficiently detect leaking components in the future. EPA should design a rule that will accommodate those new technologies, rather than stymie development in the industry by limiting monitoring to one or two methods of monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 19

Comment: The EPA is proposing to require operators to detect leaks through the use of either Method 21 or Optical Gas Imaging (OGI) cameras. While each method may be reasonably effective in appropriate circumstances, those methods are imperfect and not always suitable for conditions within the Permian Basin. High winds are often present in West Texas and Southeastern New Mexico which hamper the ability of an OGI camera to effectively detect methane emissions. Instead of prescribing a limited set of detection methods, Concho encourages the EPA to adopt a program which would allow an operator flexibility to choose a method based upon the prevailing atmospheric conditions. This would also allow an operator the opportunity to try new innovative technologies as they become available.

Response: We agree that in certain climates or weather conditions monitoring surveys cannot be performed using OGI. We have accounted for this in the requirements for the monitoring plan. For example, owners and operators must determine under what conditions, including the maximum wind speed that a monitoring survey can be conducted. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Paul D. Wehnert
Commenter Affiliation: Heath Consultants Incorporated
Document Control Number: EPA-HQ-OAR-2010-0505-6868
Comment Excerpt Number: 2

Comment: Heath believes the current proposed rule limiting technologies to only Optical Gas Imaging (OGI) precludes the use of other comparable and more accurate leak detection technologies and methodologies from being used. It also discourages the research of other new technologies and methodologies to be developed to aid in detecting leaks (emissions) from oil and gas sites. It also mentions the opportunity to utilize EPA Method 21 screening tools for leak (emissions) detection as other alternatives to the Optical Gas Imaging (OGI) but I need also inform you that this is outdated and does not include a number of current technologies that have been developed since the Method 21 requirement was instituted and even currently widely in use today.

We have confidence that allowing operators, the choice to utilize a number of leak detection technologies and not limiting them to only Optical Gas Imaging (OGI) and Method 21 screening tools will allow a higher quality of leak (emissions) sensitivity and accuracy along with more affordable options and user friendly applications that will comply with the proposed regulations.

On September 23, 2015, I attended the public hearing in Dallas, Texas and made my case for the above-mentioned. It appeared that there might be some confusion that Optical Gas Imaging (OGI) tools were all encompassing of leak (emissions) detection technologies and this is totally false. Even Method 21 screening tools do not cover all the recent leak detection technologies that have since been developed for the industry today.

Heath currently has research projects ongoing with several governmental agencies such as the Department of Energy (DOE); Advanced Research Projects Agency-Energy (ARPA-E) and the Department of Transportation (DOT); Pipeline & Hazardous Materials Safety Administration (PHMSA) that under the current proposed regulation will not meet the requirements of both Optical Gas Imaging (OGI) and Method 21 leak detection technologies.

I urge the EPA to consider all current leak detection instrumentation currently in service today and new technologies that are currently under development to meet the requirements of the proposed regulations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 3

Comment: Alternative controls and monitoring.

Technology in the oil and natural gas sector is rapidly evolving and the Division believes that it is important for EPA to allow appropriate implementation of alternate and emerging control and monitoring technologies and methods. For example, Colorado's regulation allows alternative emissions control equipment and monitoring methods, upon approval by the Division, in order to demonstrate compliance. The Division has developed a procedure for evaluating alternative controls or technologies to determine whether the proposed monitoring technology or method satisfies Colorado's LDAR inspection requirements. EPA is familiar with one of the Division's recently approved alternative monitoring technologies, Rebellion Photonics Gas Cloud Imager, as EPA has also been involved in field demonstrations and discussions concerning the technology. The approval of such alternatives by the Division does not exempt a source from an applicable emission limitation, control measure, or monitoring method, but rather acknowledges and allows for changing technologies and methods. The Division believes EPA should allow a delegated authority to approve alternative control and monitoring technologies and methods under NSPS OOOOa, or craft NSPS OOOOa such that it recognizes the use of alternative monitoring technologies and methods approved under a state LDAR program. For example, EPA could consider whether the monitoring technology or method is a qualitative or quantitative detection, the scanning or viewing range, the pollutant and level detected, any limitations, and cost. The Division also believes the approval process for such alternative control and monitoring methods or technologies should be limited to a time frame that does not render the alternative obsolete. For example, the Division reviews requests for alternative monitoring technologies and methods on a quarterly basis.

The Division also notes that the United States Department of Energy has funded projects to develop methane specific monitoring technologies and methods for the oil and gas sector. However, because NSPS OOOOa specifies OGI capable of detecting half methane and half propane, it is unclear whether these technologies could be used to comply with NSPS OOOOa LDAR. The Division requests that EPA clarify how the use of these emerging methane monitoring technologies and methods may correlate to the VOC and methane standard in NSPS OOOOa, and how and whether EPA would consider the use of those technologies and methods to show compliance with NSPS OOOOa LDAR. These new technologies may be more cost-effective than OGI and may be able to detect a different scope of pollutants or surrogates indicative of fugitive emissions, which could lead to greater fugitive emissions reductions. Further, the development of less costly monitoring technologies and methods could be important as the number of leaks detected decreases, which could mean the recovery of less saleable gas to offset the costs of monitoring. While these technologies are still under development, NSPS OOOOa as currently drafted will not allow their use for the LDAR program, except where a source obtains EPA's approval for alternative monitoring through the long and onerous Part 60 Subpart A alternative monitoring request process.

Response: With respect to the Rebellion technology or other multi- or hyper-spectral imaging instruments, please see DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 42. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Colleen Cooley
Commenter Affiliation: Diné Citizens Against Ruining Our Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6883
Comment Excerpt Number: 5

Comment: Recent and emerging advances in continuous detection technologies for methane will permit real time identification of large leaks, paving the way for optimized deployment of OGI cameras, faster fixes, and greater emission reductions. The final regulation must reflect EPA's technology-forcing authority under the Clean Air Act by allowing and incentivizing innovation in leak detection technologies and practices, including continuous detection. Without such alternative pathways, the proposed rule risks unintentionally freezing methane detection technology at its current level.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)
Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 9

Comment: EPA Should Strive For More Flexibility

As a general comment on the draft rules as a whole, and the regulatory scheme those rules intend to implement, TIPRO would strongly suggest that members of the regulated community be afforded as much flexibility in achieving compliance as possible. Rules should not dictate that a particular technology be used in compliance programs without leaving room for the possibility that better alternatives could be developed in the future. Our industry is a leading innovator of new technology and conducts more research and development than most of the other industries in the country. New methods and technologies are constantly being tested, improved, and used by operators to drive down cost and improve production and greater efficiency in the E&P process. Their drive to innovate is inherent—it comes naturally—driven primarily by the need for efficiency, better safety measures and ultimately cost savings. Each of those drivers provides an incentive for upstream operators to minimize methane emissions, and when the inevitable time comes that better compliance monitoring technology is developed operators should be free to utilize it.

As a specific example, and as explained in more detail below, the leak detection and reporting requirements ("LDAR") in the draft rules require use of optical gas imaging ("OGI") before a leaking component can be considered repaired. See e.g. §60.5397a. Yet, many other methods exist currently, and it is likely that better methods will be developed in the future. Therefore, TIPRO recommends that EPA revise the rules to allow for use of an equivalent or better method in situations like this.

When appropriate, EPA could write the rules in a way that requires advance approval before utilization of new technology. The scope of that approval could be based on the user (operator or service provider, company-wide), the geographic area (resource play-wide or statewide), or even on a case by case basis.

But regardless of the mechanism used to effectuate the goal, EPA should build in more flexibility for companies in this innovative industry to improve and use better technology without the necessity of additional rulemaking. It simply makes sense to allow the industry to follow its natural tendency to innovate.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)

Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 11

Comment: EPA Should Allow Alternatives to OGI for Leak Detection

The industry should have the freedom to choose a different leak detection technology besides optical gas imaging (OGI). The EPA rule mandating a specific technology or provider would have the effect of stifling competition and innovation. Several other technologies/systems are available or in development, in addition to OGI, including tunable diode laser absorption spectroscopy; 3- channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser-based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas leak detectors; and remote methane leak detectors.

OGI technology has significant limitations. Among them, it can be explosive if improperly used, photos can be difficult to interpret (e.g. a heat plume can be mistaken for a leak), and it can be prohibitively expensive for smaller companies and impractical for larger companies with diverse geographic locations. Further, some OGI pictures lack GPS coordinates (a proposed EPA requirement) and the technology lacks the ability to measure the amount of an emissions event.

Response: In the final rule, we also allow Method 21 as an alternative to OGI to provide owners and operators options for performing monitoring surveys. See section VI.F.1.c and section VI.F.2.b of the preamble to the final rule for more information regarding this issue. Additionally, please see response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for discussion on other technologies/systems, such as tunable diode laser absorption spectroscopy. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Stuart Spencer, Associate Director, Office of Air Quality
Commenter Affiliation: Arkansas Department of Environmental Quality (ADEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6924
Comment Excerpt Number: 2

Comment: It is ADEQ's position that EPA should not select or dictate the technology for detecting leaks. The concept behind a New Source Performance Standard (NSPS) is setting a performance standard that must be met- not dictating a particular technology. Dictating a particular technology stifles innovation. There are approximately a half dozen or more additional technologies/techniques that are being marketed and/or developed including, but not limited to: tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser-based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas lead detectors; and remote methane leak detectors. These are in addition to the existing Method 21 procedure that some companies find workable and preferable. The need and motivation to promote innovation will cease to exist if EPA dictates the technology, and there is no reason for EPA to select one technology.

Optical gas imaging/forward looking infrared (OGI/FLIR) technology suffers from numerous limitations. The results of the camera, the "pictures", are difficult to interpret and subject to misinterpretation, e.g., what appears to be a leak could simply be a heat plume. Problems with the OGI/FLIR technology are exacerbated in windy and/or cold conditions. There will be a limited supply of cameras, and for companies with diverse geographic locations, it will be difficult to comply with the short survey timeframes set forth in the proposal. The proposed regulations also require the pictures to contain GPS coordinates. Some of the cameras do not have that function, thus requiring another device to comply with the regulations. Finally, and perhaps most importantly, the OGI technology is not a quantitative tool - it is not capable of determining how much natural gas is leaking.

Response: In the final rule we also allow Method 21 as an alternative to OGI to provide owners and operators options for performing monitoring surveys. See section VI.F.1.c and section VI.F.2.b of the preamble for more information regarding this issue. Additionally, please see response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for discussion on other technologies/systems, such as tunable diode laser absorption spectroscopy. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

We also recognize that owners and operators of both wells sites and compressor stations need time to complete critical steps in order to establish their program's infrastructure and build a foundation to assure continuous compliance. For these reasons, we are requiring in the final rule that the initial monitoring survey must take place within one year after publication of the final rule in the Federal Register or within 60 days of the startup of production for well sites or 60 days after the startup of a new compressor, whichever is later.

Commenter Name: Terry L. O'Clair, Director, Division of Air Quality
Commenter Affiliation: North Dakota Department of Health
Document Control Number: EPA-HQ-OAR-2010-0505-6928
Comment Excerpt Number: 4

Comment: North Dakota has found the use of optical gas imaging/FLIR cameras to be valuable. However, adverse weather (cold, rain, wind, or snow) can limit the usefulness of information obtained. These conditions are often found during winter months. For example, cold weather (less than 32 degrees) and wind (15-20 mph+) result in less than optimal conditions for assessments to be made. To maintain quality data, more time will be necessary to complete testing. The draft rule should also allow alternative detection methods/technologies to be utilized as necessary and as the technologies are developed.

Response: The EPA has revised the final rule to allow exemption of quarterly monitoring during extreme temperatures affecting instrument operation. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

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Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 21

Comment: The proposed rule also would stifle innovation of more effective monitoring and measuring equipment. Instead of prescribing two methodologies, the rule should permit flexibility, in accordance with other successful LDAR programs. For example, in Colorado, 5 C.C.R. 1001-9 (Regulation 7) gives operators some flexibility in choosing a leak detection technology. EPA's vendor testing program for flares and combustors may also be another viable option. Under this program, EPA allows vendors to test according to protocols set by EPA and determine standard operating procedures for control devices. New and innovative technologies are constantly involving in this space and the rule should encourage not stifle such progress. We encourage EPA to make very clear in the rule that new technologies are encouraged and will be approved and allowed through a straightforward and expedited review process (*i.e.*, avoiding an onerous, years-long application process that would otherwise be applied to actual emissions control devices or continuous emissions monitoring systems). We would welcome the opportunity to work with EPA to determine what methods should be approved for LDAR monitoring and verification.

Response: Owner operators are given the flexibility to choose OGI, Method 21 and the variants within those categories. Additionally, see response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 25

Comment: <u>EPA Must Provide Operators Flexibility to Incorporate New Monitoring Technologies</u>

In the proposed rule, EPA specifically authorizes the use of OGI for fugitive emissions monitoring, while allowing the use of Method 21 for certain other monitoring activities. Given the rapidly changing landscape for fugitive emissions monitoring, GPA urges EPA to adopt a flexible approach that allows operators to use alternative monitoring technologies, provided they are as effective as OGI in detecting fugitive emissions. As discussed above and described in more detail in API's cost analysis, the costs associated with EPA's proposed fugitive emissions program—including the use of OGI technology—are significant. Moreover, the field of fugitive emissions detection is rapidly changing, with a number of new technologies for imaging and remote detection under development. Some of these technologies could dramatically reduce the costs of fugitive emissions surveys, particularly in the remote areas where many wells sites and compressors station sites are located. Rather than creating a binding obligation to use OGI (and in some circumstances Method 21) for all fugitive emissions surveys, GPA urges EPA to build into the regulations the necessary flexibility to allow for the use of other monitoring technologies, provided they are as effective as OGI. Including such a provision in the regulations will allow operators with much-needed flexibility without the regulatory burden of having to seek revision of Subpart OOOOa in the future to use other, equally effective monitoring technologies. As part of the President's Strategy to Reduce Methane Emissions—the same strategy document that requested these new methane regulations from EPA—the Department of Energy is funding research to develop "new measurement technologies, including lower-cost emissions sensing equipment." EPA should ensure that any new technologies developed through this program can be incorporated into the LDAR program without the need for complex and time-consuming regulatory action.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 21

Comment: EPA must not selectively favor certain methane detection technologies

In addition to monitoring frequency, addressed above, we have other concerns with the proposed LDAR program. The proposal suggests relying solely on OGI or Method 21 for monitoring and repair-but such constraints are self-limiting and ignore existing, successful LDAR programs and methane detection technologies. OGI and Method 21 are reasonably effective technologies for LDAR applications; however they are imperfect and may not function well in all situations.

For example, OGI is also not a quantitative tool and depending on the camera, it may also detect water vapor and heat signatures. An OGI camera survey may not always be able to tell an operator whether a repair is necessary since it is not quantitative. During periods of overcast skies, high winds, or inclement weather, OGI technology is unable to effectively detect hydrocarbon vapors. Lastly, OGI cameras are generally not intrinsically safe and would require a hot work permit in many instances. Thus, a prescriptive LDAR rule that relies too heavily on an OGI monitoring plan will be ineffective in many situations. While OGI cameras have their place in certain circumstances, they are inherently limiting in their utility within an LDAR program particularly one so focused on defining leaks and leak percentages such as that being proposed.

For a more flexible and cost-effective LDAR program, the rule should give operators the ability to select from various monitoring technologies to best perform at that operator's facilities and for its personnel. The proposed rule would stifle innovation through use of equally or more effective monitoring and measuring equipment either individually or in varying combinations. Instead or prescribing two methodologies, the rule should permit flexibility, in accordance with other successful LDAR programs. For example, in Colorado, Regulation 7 gives operators some flexibility in choosing a leak detection technology. EPA's vendor testing program for flares and combustors is an example of similar regulatory flexibility to accommodate existing, effective technologies. Under this program, EPA allows vendors to test according to protocols set by EPA and determine standard operating procedures for control devices.

New and innovative technologies are constantly evolving in this space and the rule should encourage and not stifle such progress. EPA should make very clear in the rule that new technologies are encouraged and will be approved and allowed through a straightforward and expedited review process (i.e., avoiding an onerous, years-long application process that would otherwise be applied to actual emissions control devices or continuous emissions monitoring systems).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. With respect to OGI instrument use for identifying leak percentages, we have revised the rule for a fixed frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Stuart A. Clark, (Washington), Co-President and Ursula Nelson, (Pima County, AZ), Co-President
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6961
Comment Excerpt Number: 9

Comment: Further, we note that the technologies available for leak detection are improving rapidly. In addition to expanding state options though the inclusion of Method 21, the final rule should include a mechanism to approve new leak detection techniques and technologies for use by states. This could be accomplished by including guidelines in the final rule to ensure that any new method or technology meets basic quality requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: J. Jared Snyder, Assistant Commissioner for Air Resources, Climate Change Energy
Commenter Affiliation: New York State Department of Environmental Conservation (DEC)
Document Control Number: EPA-HQ-OAR-2010-0505-7006
Comment Excerpt Number: 8

Comment: Furthermore, the DEC recommends that EPA account for new and improving technology by defining a placeholder in the regulation which would allow for the approval of new leak detection technologies with an expedited approval process. The DEC has utilized this type of language in a number of its area source rules with success.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 12

Comment: In addition, TCEQ recommends that the EPA allow alternate methods of monitoring rather than limiting it to the OGI technology that is currently proposed. Requiring the use of OGI technology as the sole compliance tool for the proposed LDAR program not only precludes the use of other comparable, and sometimes more accurate, leak detection equipment and methods, but also discourages the research of other new technologies and mechanisms to aid in detecting leaks from oil and gas sites.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Alan Krupnick, Jan Mares and Clayton Munnings
Commenter Affiliation: Resources for the Future
Document Control Number: EPA-HQ-OAR-2010-0505-6918
Comment Excerpt Number: 1

Comment: The proposed rule should have the ability to accommodate new information given our rapidly changing understanding of technology for measuring and reducing those emissions from the oil and gas sector. For example, although EPA is requiring optical gas imaging for leak detection and repair (LDAR) programs, cheaper and equally effectively alternatives may be available in the future. The rule should be altered to permit such technology substitutions. In general, we believe the proposal does not recognize the enormous diversity of company activities, holdings, or means of accomplishing LDAR programs and recommend that EPA consider whether companies may be able to use more tailored approaches if they meet certain criteria.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 15

Comment: As written, a fugitive emission detected in an LDAR survey may only be defined through observance with an optical gas imaging system. By prescribing a specific technology to identify these emission, the regulations do not allow for inclusion of fugitive emissions detection technologies available today that may be equally effective or new technologies that have not yet been fully developed. This, in turn, stifles future technology innovation which may potentially detect emissions more efficiently and cost-effectively.

Additionally, the current optical gas imaging equipment is qualitative in nature and imprecise, which can lead to the misidentification of water and other vapors as methane fugitives. Therefore, the regulation should be revised to allow for the development and implementation of better emission-detection technology rather than requiring optical gas imaging.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Steve Henke
Commenter Affiliation: New Mexico Oil and Gas Association (NMOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6850
Comment Excerpt Number: 6

Comment: The concept behind New Source Performance Standards is setting a performance standard that must be met – not dictating a particular technology. Dictating a particular technology stifles innovation. In addition to accepted Method 21, there are approximately ½ dozen additional technologies/techniques that are being marketed and/or developed. The need and motivation to "build a better mouse trap" will cease to exist if EPA dictates the technology and there is no reason for EPA to select one technology.

Response: Concerning the comment that the EPA should not specify a detection technology, we disagree. The EPA has a long history of establishing fugitive emissions monitoring programs, such as that established in subparts VV and VVa. These rules are based on specifying the detection technology to be used. Additionally, we are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. We have also finalized a pathway for the use of emerging technology. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 12

Comment: EPA must allow flexibility in methodologies used for inspection for fugitives monitoring.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Andrew Casper
Commenter Affiliation: Colorado Oil & Gas Association (COGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6889
Comment Excerpt Number: 14

Comment: Flexibility is also important with respect to inspection and repair technology. Colorado's experience has demonstrated that: 1) OGI is not appropriate for all weather or site-specific conditions; 2) AVO is rarely effective in a low-pressure coalbed methane (CBM)/dry gas field; 3) alternatives to AVO are of little environmental benefit because leaks at CBM well sites are small, low volume, and the stream does not contain VOCs; 4) repeated LDAR surveys produce little environmental or economic benefit; and 5) use of a soapy water solution (as described Method 21, Section 8.3.3) is very effective at identifying the location of a range of leak sizes and repair of the same. Moreover, prescribing a specific monitoring method/technology, such as OGI or the use of portable instruments, as the only monitoring method does not provide flexibility to adopt emerging technologies on a timely basis and may have the unintended consequence of stunting future innovation in fugitive emission detection methodology. In fact, many operators performing repairs will not have access to portable analyzers, let alone carry such analyzers with them at the time a leak is noticed and repair is made. Further, from a practicality standpoint, unless the individual who discovers the leak also repairs the leak at the time of discovery, any verification method that automatically requires the use of a camera or portable analyzer adds additional steps to the process and does not necessarily improve emissions. By allowing the use of the alternative screening procedure in Method 21, the number of leaks that would have to be verified using a camera or portable analyzer are minimized (or reduced only to those where a soapy water solution is ineffective), thereby reducing effort, number, cost, and time required for site re-visits to verify repairs. COGA believes that, by accelerating or streamlining approval of new technologies and methodologies, operators are more likely to invest in and implement more efficient and cost-effective technologies. Therefore, EPA should consider accelerating the alternative method approval process in order to encourage a better rate of compliance and achieve a greater reduction of fugitive emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. See response to DCN EPA-HQ-OAR-2010-0505-6810, Excerpt 7 for a discussion regarding monitoring frequency.

We did not finalize AVO requirements for fugitive emissions monitoring; however, owners and operators must maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers fugitive through audio, visual or olfactory means, the owner or operator has a general duty to repair these components.

We are finalizing that Method 21 can be used as an alternative to OGI. Concerning the use of a soap solution to detect leaks, we are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more information regarding this issue.

Commenter Name: Lindel Fowler, Acting Executive Director
Commenter Affiliation: Railroad Commission of Texas
Document Control Number: EPA-HQ-OAR-2010-0505-6917
Comment Excerpt Number: 6

Comment: With respect to leak detection and repair (LDAR), the Commission has concerns about the use of Optical Gas Imaging (OGI) as the only method of demonstrating compliance with LDAR requirements. The Commission agrees with TCEQ's comment that limiting the LDAR compliance tool to OGI technology both precludes use of other comparable leak detection methods and inhibits innovation by minimizing the value of research into new leak detection technologies and methods at oil and gas sites.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 41

Comment: In addition, the rule should allow for requirements that are flexible enough for other instrumental methods, such as AVO, or for new monitoring methods that have not yet been developed.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

We did not finalize AVO requirements for fugitive emissions monitoring; however, owners and operators must maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers fugitive through audio, visual or olfactory means, the owner or operator has a general duty to repair these components.

Commenter Name: John W. Mitchell
Commenter Affiliation: Kansas Department of Health and Environment (KDHE)
Document Control Number: EPA-HQ-OAR-2010-0505-6804
Comment Excerpt Number: 2

Comment: EPA is proposing the use of optical gas imaging (OGI) instruments for leak detection and repair (LDAR) programs. OGI instruments are expensive to purchase and a relatively new technology that requires a high level of training to operate. OGI is a useful tool, but EPA is relying too heavily on this technology to detect leaking equipment. To quote the Preamble, "EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation provided that the right operating conditions *(e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI." The climate in Kansas is highly varied in terms of wind and temperatures which has been demonstrated to negatively affect the functionality of OGI. In Kansas, this technology produces data more akin to qualitative than quantitative results.

In addition, by requiring OGI monitoring exclusively, the rule precludes the use of other leak detection equipment and methods that may be more cost-effective and appropriate for the equipment and sites being evaluated.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Stuart A. Clark and Ursula Nelson, Co-President
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6932
Comment Excerpt Number: 9

Comment: Further, we note that the technologies available for leak detection are improving rapidly. In addition to expanding state options though the inclusion of Method 21, the final rule should include a mechanism to approve new leak detection techniques and technologies for use by states. This could be accomplished by including guidelines in the final rule to ensure that any new method or technology meets basic quality requirements.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 12

Comment: Rule must not define OGI and should provide for technological advancements and innovation

Although Pioneer currently favors OGI technology over Method 21 and utilizes OGI routinely in the field to conduct voluntary monitoring throughout its asset areas, Pioneer agrees with IPAA/AXPC's comment that EPA should not select or dictate the technology for detecting leaks. The concept behind NSPS is setting a performance standard that must be met - not dictating a particular technology since this stifles innovation. Pioneer suggests that EPA leave the possibility open for new technology that may be easy, faster, and more effective, reliable and/or cost-effective than the current IR cameras technology available today. Pioneer suggests that EPA could add the language, OGI "or equivalent technology" in §60.5397a. Colorado Regulation 7, while holding OGI and Method 21 as the standard, does not by intent limit industry to only those two options and has set out procedures for gaining approval to employ alternative approaches. Colorado's "approved instrument monitoring method" is "an infra-red camera, EPA Method 21, or other Division approved instrument based monitoring device or method. Any instrument monitoring method approved by the Division must be capable of detecting leaks as defined in Section XVll.F.6. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations."

EPA should also consider ongoing technology development initiatives, including the Department of Energy ARPA-E MONITOR Program and the Environmental Defense Fund Methane Detector Challenge, and not impose a regulatory framework that would stifle future innovation. EPA needs to anticipate and promote implementation of new emission detection technologies that have the capability to help industry smartly direct their inspection and maintenance efforts, quickly locate unexpected emissions, and detect emissions that may be intermittent in nature.

Response: Concerning the comment that the EPA should not specify a detection technology, we disagree. The EPA has a long history of establishing fugitive emissions monitoring programs, such as that established in subparts VV and VVa. These rules are based on specifying the detection technology to be used.

Additionally, we are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 27

Comment: Leak survey methods are expected to expand with new and emerging methods as hundreds of well sites may be subject to leak detection programs once NSPS OOOOa is promulgated. With many new leak survey vendors expected to provide services to meet the needs of regulated operators, PAW expects the leak detection equipment to expand beyond the current OGI and Method 21 survey approaches. EPA should allow any new technology to be used if that technology is equivalent to OGI or Method 21 in detecting leaks. In addition, since OOOOa does not require quantification of leak rates, such new technologies need only demonstrate that they can detect, not quantify leaks.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Greg Guidry
Commenter Affiliation: SWEPI LP
Document Control Number: EPA-HQ-OAR-2010-0505-6892
Comment Excerpt Number: 6

Comment: FOSTERING INNOVATION

Leak detection and repair (LDAR) is a key area in which technology and practices are rapidly advancing and as such the finalized rule should include language to foster innovation. In this regard, Shell along with seven (7) other oil and gas companies have partnered with the Environmental Defense Fund (EDF) in a program to identify and commercialize new methane detection technologies at low cost for the continuous monitoring of unintentional methane emissions. This program is called the Methane Detectors Challenge.

Continuous monitoring and alternative technologies can potentially optimize worker deployment in a timely fashion to the right locations where handheld optical gas imaging (OGI) could be deployed to identify and repair leaks onsite more quickly. This complementary action could support increased emission reductions with increased mitigation speed.

Further reinforcement of innovation is provided by EPA in the following statement: "While R&D efforts were essential to achieving improvements in FGD scrubber technology - and are also very important to improving carbon capture technologies, the influence of regulatory actions that establish commercial markets for advanced technologies cannot be minimized." 80 FR 64575

Moreover Colorado Reg 7, which includes flexibility for technological improvements over time, shows how well-designed policies encourage innovative leak detection. Shell believes that the final NSPS should also foster efficient processes for the commercial deployment of innovative technologies and work practices; including but not limited to continuous methane detection and that the currently proposed approach supports unintended consequences of potentially stalling innovative technologies in general.

Shell's recommendations for final rule include the following; (1) minimum criteria by which monitoring effectiveness will be evaluated (i.e. detection level, repeatability, environmental robustness, safety); (2) process for technology approval; (3) post technology approval, the Agency should facilitate market speed by minimizing requirements for technology adoption; and (4) relief should be afforded to operators in the form of a reduction of onsite monitoring with the use of proven technologies and timely repair.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 11

Comment: Provisions for New and Developing Technologies

Similar to the recommendation for alternative monitoring and measurement devices, SWN recommends that EPA structure the regulations to have the necessary flexibility to allow the use of new and developing monitoring technologies.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 14

Comment: We fully support the opportunity to utilize the OGI instrument or Method 21 (including soap bubble) to re-survey a repaired component. We would recommend that provision be extended to alternative monitoring and measurement devices (e.g. Heath RMLD or similar).

Response: The final rule allows fugitive emissions monitoring with Method 21 as alternative to OGI monitoring. The final rule also allows the use of soap solution, as specified in Method 21 for resurveying repaired components. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 7

Comment: Accepted leak detection methods, including EPA Method 21, should be allowed for leak surveys.

EPA's proposed LDAR program to address fugitive emissions from compressor stations would require leak detection surveys using OGI technology to the exclusion of other equivalent methodologies. EPA's proposal provides no valid justification for limiting the leak survey methodology to OGI and excluding equivalent and approved survey methodologies.

EPA's requirement that leak detection surveys be conducted using OGI technology represents a shift in the Agency's long-standing approach to using Method 21. In fact, LDAR programs in other EPA regulatory programs, including NESHAP and MACT regulations and EPA's GHGRP for oil and gas operations, allow the use of Method 21, as well as state LDAR programs.

EPA bases its BSER analysis on the use of OGI after making a determination that OGI is more cost effective than Method 21. However, many factors can influence survey costs, including, as EPA recognizes, the availability of trained OGI contractors. Yet EPA fails to take into account this cost when evaluating the cost of OGI against the cost of Method 21. As a result, EPA's determination to focus its BSER analysis on the use of OGI is flawed.

The fact that Method 21 is more cost-effective than and as equally effective as OGI is bolstered by EPA's proposal to allow the use of Method 21 for resurveys of previously identified and repaired leaks. As EPA recognizes, for repairs/replacement that cannot be made at the time the leak is discovered, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective as compared to Method 21. As such, EPA is proposing to allow the use of Method 21 for the resurvey. Allowing the use of Method 21 for these resurveys indicates that EPA is as comfortable with the level of leak detection afforded by Method 21 as it is with OGI. EPA has no valid reason for limiting the use of Method 21, or any other equivalent leak detection method for the initial leak detection survey.

The operator should have the discretion to use established methods for leak surveys, and Method 21 is the longstanding standard. The final rule should include Method 21 and the ability to implement other technologies that are proven equivalent to OGI or Method 21. If not, this program will be inconsistent with other leak mitigation programs in the U.S., as well as Subpart W leak survey methodology.

Response: We are allowing the use of Method 21 in the final rule. See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2, and sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 7

Comment: WBI Energy strongly recommends allowing the same monitoring methods as described in 40 CFR 98.234. The monitoring required in 40 CFR 98.234 is conducted on the same type of equipment and for the same pollutants as in the proposed rule. Many companies, such as WBI Energy already have programs in place for conducting these types of surveys using alternative methods to OGI. Additionally, WBI Energy recommends including a statement that allows the Administrator to approve additional monitoring methods that effectively identify leaks from fugitive emissions sources so that new technologies that may be developed could be used. Only allowing OGI would be an unnecessary burden for companies that already have an alternative monitoring method in place by forcing them to scrap their existing programs and equipment and substitute a technology that may or may not be more cost effective.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. See section VI.K of the preamble to the final rule for more information on equivalency determinations for existing programs.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 19

Comment: The specification of a technology based rather than a performance standard is inconsistent with feedback EPA specifically requested and received from small business entities and will result in unnecessary burdens (e.g., financial and technical) on such entities.

One of the small entity's primary concerns, expressed during the outreach program prior to proposal of the Subpart OOOOa, was EPA's stated intent to require OGI as the LDAR technology in the rule. During the proceedings, small business entities explained their real world experiences and successes with non-OGI LDAR options. While such options could be considered more labor intensive than OGI, they are less costly and equally, if not more effective in identifying leaking components, quantifying total hydrocarbon concentrations of leaking components and, after repairs, providing quick and decisive documentation of compliance.

Response: We are allowing the use of Method 21 in the final rule. See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2, and sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Comment submitted by Todd Parfitt, Director
Commenter Affiliation: Wyoming Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2010-0505-6993
Comment Excerpt Number: 6

Comment: FM plans based solely on AVO may not be as effective at detecting small leaks as FM that includes Method 21 or OGI, if AVO is proposed in addition to periodic Method 21 or OGI monitoring, there can be a benefit from additional monitoring, which is one reason AQD has approved FM protocols that include AVO. The EPA must allow additional flexibility in determining appropriate fugitive emissions monitoring methods for FM plans, especially when there are technical limitations for OGI and there can be benefits from additional monitoring that may not necessarily be OGI or Method 21.

Response: We agree that AVO monitoring in combination with OGI or Method 21 can be an acceptable form of monitoring but AVO alone is not. The final rule requires owners and operators to maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers a leak through audio, visual or olfactory means, the owner or operator has a general duty to repair these components.

See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)

Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 10

Comment: Item - Alternate Monitoring and Measurement Devices

Southwestern Energy supports the proposed rules acceptance of OGI and inclusion of Method 21 for the purpose of conducting fugitive emissions surveys. However, there are other monitoring and measurement instruments that are on the market that may be further "enhancements" or "alternatives" for these two options. In addition, there will be emerging monitoring and measurement devices when these rules are final.

As an example, SWN utilizes Heath Consultants Remote Methane Leak Detector (RMLD) in many of our fugitive emissions surveys. The RMLD operates on a tunable diode laser absorption spectroscopy "platform". This instrument is "tuned" for detecting methane emissions which is beneficial to SWN' s operations which are primarily shale gas related (and hence very high methane concentration). The RMLD provides an audible alarm when a "leak" is detected as well as a visual readout of "concentration" (in terms of ppm-m). The RMLD can detect leaks well below 500 ppm and yet can scan components/equipment in a similar manner as an OGI instrument. In essence, for methane fugitive monitoring surveys it provides the benefits of both Method 21 devices (<10,000 ppm "measurement"), yet the "time reductions" of the OGI. The RMLD also provides the benefit of an audible alert when a "leak" is detected.

The above is but one example of a market ready, demonstrated in practice fugitive emissions monitoring instrument that would assist in identifying more leaks and achieving more reductions. There may be others that exist and others under development.

Recommendations:

The final rule should have provisions for allowing the use of alternative or additional monitoring and measurement devices such as the Heath Consultants RMLD addressed above. Those provisions could be established under the "Custom Plan" recommendation above or similar to the provisions for Method 21 under Subpart A, Appendix A (whereby the performance specifications are specified, but not the specific instrument) or by the agency developing a list of alternative monitor/measurement devices that may be utilized.

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17, for more information on tunable diode laser absorption spectroscopy.

Commenter Name: Jack Schwaller
Commenter Affiliation: HOERBIGER Corporation of America, Inc.

Document Control Number: EPA-HQ-OAR-2010-0505-6799
Comment Excerpt Number: 8

Comment: **Benefits of alternate methods**

1. "Early warning" catches leaks before they get excessive
2. Will give more time to plan outage. Accommodates preventive maintenance.
3. Temperature monitoring is continuous. Mass Flow monitoring can be.
4. Can easily be added to existing unit control panel/monitoring system.
5. Will not have to open the distance piece to "shoot" the case/rod.
6. Don't need a special "Green Team" to come out to test.
7. Lower testing cost if site has few units
8. More accurate and consistent

Response: We are finalizing that Method 21 can be used as an alternative to OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 1

Comment: I'm with a small company called Lasen. We have developed an infrared LIDAR, a laser sensor system, applied along the pipelines between 150 to 300 feet at 65 miles an hour. We record the full pipeline visually and give accurate GPS markings of each leak we find. We have a sensitivity of 5 parts per million. And it's been proven on several government tests. Our accuracy is 98 percent.

Since 2004 we have flown over 200,000 miles and found over 20,000 leaks. The DOT put out a report, and I have it here in the packet for you, of between 2005 and 2011, we have saved 2.933 trillion BTUs of methane energy because we have detected those leaks; and we prevented 46,000 tons of carbon from escaping into the atmosphere.

We give a report within 24 hours after we fly the lines, with GPS location of the leaks. The oil companies, we have several of them that are applying for them and were very happy with our source.

Now, after saying all that, the reason why I'm here is we read through your regulations, and any oil company reading through them will determine the only system that you endorse is the IR camera or the OGI. It's a good system. It really is -- and we have tested it quite a few times -- when you can control your environment, you have a -- and have the persons trained to operate it.

But even in the best scenario, we say it's fit only about for 10,000 parts per million -- 10,000 --. We have found that, in aerial surveys, it's only -- the best it can possibly do is just 30,000 parts per million detection of methane.

We are very concerned because on Page 117 and 166, you say it is the best system out there for detecting methane. Any oil company reading your report will think that you endorse the IR camera only, and all other systems out there are null and void. And our experience is that the majority of the leaks that we find are below the 10,000 parts per million.

But if you keep the verbiage the way it is, the oil companies are going to think that this is the only system you endorse, and you are going to miss the 90 percent of the leaks that are out there.

Response: The EPA is aware of other available technologies (i.e., tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas leak detectors; and remote methane leak detectors). These technologies are generally too costly, cannot be universally applied due to technical limitations (e.g, necessity for hard target), represent incomplete solutions for fugitive emissions management (e.g, action levels for path averaged concentrations with varying path lengths), or lacking the supporting documentation (e.g, equivalence with proposed OGI, fugitive emission systems expected emission reductions). While we are not taking action on allowing these as the BSER or as an alternative, we encourage the continuing development of leak detection systems in this sector. We have also included requirements for the application of emerging technologies for monitoring fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 17

Comment: Gas companies should be given the choice to choose what appropriate and improved monitoring levels can be used. For an example, Apogee has been providing a fully vetted and award-winning mobile leak monitoring system to the natural gas and oil community for over a decade. The LDS is an elegant solution that measures methane, total hydrocarbons, and CO_2 simultaneously and individually at 25 parts per million lower detection limits and at a speed of 50 hertz.

That means that these detectors, they're mobile detectors, can be used on ground vehicles at highway speeds, or be they trucks or ATVs in off-road conditions, or from helicopters or used in airborne sampling.

The example I'd like to give you is that a gas company in West Virginia approached us to use the LDS unit for some helicopter surveillances of their operation where they had not only well operations in mountainous areas but also ran their connecting pipe-lines across a piece of these mountains, making it very difficult to get to them by either trucks or by walking leak detection surveys.

The -- this part of the country is loaded with deciduous trees, so you get a tree canopy that makes it impossible, literally, to use things like LIDAR or the IR camera systems to be able to spot the leaks. On the other hand, the system we have, the leaks came to us. So it worked very effectively for them. And again, it points out the fact that gas companies should be able to use whatever works best for what their needs are.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 206

Comment: Good morning. My name is Dirk Richter, and I live in Longmont, Colorado. And I'm the owner of a company. It's a small company that I started last year.

Over the last 15 years, I've been a research scientist and engineer working at the National Center for Atmospheric Research in Boulder and the University of Colorado. And during this time, I carried out airborne air quality studies with NASA and NOAA and National Science Foundation-sponsored projects. Last year I started a company, which entered the Methane Detector Challenge issued by the Environmental Defense Fund, in partnership with eight major oil and gas companies, with the goal to development smart, cost-effective sensors that can provide continuous unmanned leak protection for every well production site in the nation.

Natural gas has become an important piece of the total U.S. energy mix today and foreseeable future, and when done right represents the least carbon- polluting fossil fuel resource.

Emissions from gathering and distribution of natural gas caused by unintended leaks, however, can have several significant impacts, including: Air quality: Hitchhiking volatile organic compounds contribute to high ozone levels and toxic gases such as benzene, impact the safety of workers and residents that live in close proximity to production sites; Second, climate system: The warming potency of methane released in the atmosphere is 80 times of CO_2; and with trillions of cubic feet of production each month, leak rates as small as 1 percent have a significant impact to the climate system; And, third, lost revenue: Even at 1 percent leak rate, that is currently the lowest estimated leak rate, over $1 billion simply evaporates into the atmosphere.

Innovative solutions to address this problem are becoming available. These market-ready solutions go above and beyond the currently successfully applied technologies and lead to win-win situations for all stakeholders. Specifically, the benefits of continuous, autonomous, and on-site leak detection are complementary to existing leak detection efforts but offer the following additional benefits:

Operators know the leak size and location of well sites that have leaks and can instantly deploy their LDAR team efficiently and thus reduce truck rolls and associated overhead costs; Leaks can be fixed in hours, not months. This is of tremendous value, especially for larger leaks; The amount of gas saved is much -- much more than the capital cost of continuous autonomous monitors, which have little to no associated labor costs for years of dependable service; Operators can prove that they are near zero emissions and radically improve the safety of on-site workers and ensure the safety of residential complexes in cases of urban developments; Operators gain insight to the frequency and failure rate of components which are causing the leaks and, hence -- and, hence, can continuously improve infrastructure and reduce costs.

In the past year, our company, together with the Environmental Defense Fund and eight major oil and gas companies, including Anadarko, Noble, and Shell, we have been innovating and testing real-world solutions, which will be entering a pilot phase with operators early next year.

Our low-cost sensors are developed and made in Colorado and use one of the world's most sensitive, rugged, laser-based sensor technology that our team, with decades of experience of laser technology, has tirelessly been developing over the course of this last year.

Two rounds of independent industrial testing at the Southwest Research Institute in San Antonio, Texas, have confirmed our breakthrough technology and showed strong results. The sensing solution cost per site is a fraction of the cost saved by reducing the leak rate by just 1 percent.

It is of utmost importance that this particular and other future innovative initiatives will be embraced in any forthcoming regulation policy and rules.

As regulations move forward, incentives for technology innovations that result in win-win situations must be embraced and perhaps even rewarded; otherwise, progress towards -- progress towards leak-free natural gas production can be slowed. And progress in making natural gas the cleanest fossil fuel energy requires innovation, cooperation, and cost-effective solutions, especially in a down-market environment. We hope that such considerations will be included in forthcoming regulation and policy that is currently under review. Thank you.

Response: The EPA thanks the commenter for this information. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 25

Comment: The Proposed Rule requires OGI for leak detection, and EPA requests comments on whether additional methods should be allowed. PAW strongly supports flexibility in the leak detection methods allowed for surveying or resurveying repaired components. EPA should allow for the use of Method 21 including soap bubbles as outlined in section 8.3.3, OGI, or infrared laser beam illuminated instruments as options for leak surveys or resurvey for verification of repair. Soap bubbles in particular should be allowed as it is a benefit to operators particularly small operators with few or small sites where other methods are not cost effective particularly for small sites with component numbers well below EPA's model plant. Particularly for repair verification, soap bubbles are already approved in method 21 due to its effectiveness, and this method doesn't require the costly use of trained OGI operators and crews to resurvey a single repair.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Concerning the use of a soap solution to detect leaks, we are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate. See sections VI.F.1.e and VI.F.2.d of the preamble for more information regarding this issue.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 38, 39

Comment: Because of its effectiveness and inexpensive components, the PBPA also requests that the soap-and-bubble method be allowed for both initial surveys and repair follow-up. This is an effective and inexpensive method to find leaks and does not require a large capital allotment for either outside contractors of for $100,000.00 cameras.

Response: We are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate. We are not allowing this alternative screening procedure for initial monitoring as its use is limited to certain components as specified within Method 21. See sections VI.F.1.e and VI.F.2.d of the preamble for more information regarding this issue.

Commenter Name: Stephen P. Hoover, Chief Executive Officer (CEO)
Commenter Affiliation: PARC
Document Control Number: EPA-HQ-OAR-2010-0505-5253
Comment Excerpt Number: 3

Comment: PARC is pleased to read that as part of the proposed rule, EPA is interested in requiring owners and operators of oil and gas well sites and compressor stations to survey and monitor fugitive emissions. We believe that such a requirement is essential to reducing methane and VOC emissions. However, we are concerned that by limiting the compliant means of surveying and monitoring fugitive emissions to specific technologies, namely optical gas imaging (OGI) and Method 21, EPA is unintentionally limiting the beneficial impacts of the proposed amendments to NSPS, and the way in which operators can comply.

A number of sensing technologies are emerging that have the capability of detecting extremely low leak rates with high accuracy, are expected to cost a fraction of optical sensors, do not require manual operation, and can continuously monitor target sites. Allowing the compliant use of these technologies would enable much wider implementation of fugitive monitoring equipment with a reduced burden to operators. In particular, a low-cost system with high sensitivity and selectivity that could be installed at each facility and operated automatically or remotely would be of immense benefit. Such systems are being developed and the option for their utilization should be included in any final ruling on NSPS.

One example of such a technology is based on chemoresistive (or "conductometric") sensor arrays. These are electronic sensing systems based on materials that change their electrical resistivity in the presence of gas. Different sensing materials have different sensitivities to different gases, therefore allowing identification not only of methane, but of other components of natural gas, including potential hazards such as hydrogen sulfide (H28). Gas species determination is achieved through comparative analysis of different sensor responses, through principal component analysis or regression techniques.

Today, scientists have already identified multiple materials that have chemoresistive responses to different gases. These include carbon nanotubes (CNTs), metal oxides, conductive polymers, as well as combinations of materials, such as CNTs adorned with metal catalysts. Along with chemoresistive sensors, there are many other gas sensing modalities that may be applicable to fugitive emissions detection. These include potentiometry, amperometry, surface acoustic waves, quartz crystal microbalances and others. Figure 1 shows measured data from two different sensor materials in the presence of extremely low levels of methane. [Figure 1 shows the responses of two representative chemoresistive sensor materials to low levels of methane]

Fortunately, there have been rapid advancements in these technologies, and we expect a number of them to reach a sufficiently mature level for deployment for methane detection in the near future. Additionally, if the proposed ruling were broadened to be inclusive of other emerging technologies, the market would likely react and propel their development, whereas excluding them could hamper development.

In addition to including other detection technologies in the final ruling, we suggest that EPA specify a set of metrics that emerging technologies must be capable of achieving before being added to the list of methods that comply with the proposed ruling. This approach would forestall excluding technologies through oversight, while ensuring sufficient sensor performance. Potential target metrics might include system sensitivity to methane or other gases of interest, or system selectivity of methane in the presence of potential interfering gases, including carbon monoxide (CO), ammonia (NH3), or others. We suggest a sensitivity target of 1-2 ppm as a baseline for detecting very low leaks, on the order of 6 scfh (depending on sensor placement and weather conditions). Selectivity could be defined as a maximum false positive rate for specific interfering gases, and should be as low as one per year in the presence of ambient gas level fluctuations in the vicinity of the installation. The false-positive rate is an important metric for technology adoption, in particular for automated continuous monitoring solutions for which false positives can lead to unnecessary site visits. A thorough verification protocol could be specified through which the sensor must be exercised before it is allowed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Dayle McDermitt, Vice President, Research and Development
Commenter Affiliation: LI-COR, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-5413
Comment Excerpt Number: 3

Comment: Alternate sensing methods should be in place to ensure leaks are identified in a timely manner in all environmental conditions. Permitting the use of only optical imaging devices for leak detection may limit identification of leaks in conditions that interfere with the imaging device technology, and will not ensure timely detection.

To fully understand the level of emissions present at oil and gas operations, quantifying GHG and/or VOC emissions should be an objective at each pad, pipeline, processing facility and distribution location. Modeling may be acceptable in contractual agreements, but not in attempting to quantify and stop emissions across hundreds of thousands of operational sites, some of which may have been in operation for decades. Too much variability is likely to exist in age and condition of equipment to allow the application of blanket coefficients for leakage rates at valves, pumps, storage tanks, compressors, etc.

Response: We have increased the flexibility regarding fugitive emissions monitoring technologies. See responses to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2 and DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.. In response to fully understanding the level of emissions present at oil and gas production facilities, we are collecting information, through a formal information collection request, that will provide additional data on oil and gas production, including emissions data.

Commenter Name: John Hampp
Commenter Affiliation: NextEra Energy, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6873
Comment Excerpt Number: 11

Comment: We urge EPA to prescribe alternative methods of compliance for addressing leaks. The proposed rule requires a Leak Detection and Repair Program (LDAR) for such equipment as piping components, hatches, seals, and compressors using gas imaging technology (i.e. FLIR cameras) as well as establishing well-defined periods for the conducting of surveys and repairs.

FLIR camera equipment is costly with an estimated cost range between $150,000-200,000 per device. Many companies would likely need to utilize third party vendors to perform surveys. Costs have been estimated as high as $1,000 per site per vendor visit. This results in an additional cost burden on companies that own and/or operate multiple sites. Alternative options for leak detection include, but are not limited to, the allowance of longer time intervals between surveys, alternatives to FLIR technology, utilization of work practice standards in lieu of leak surveys, and/or best available monitoring methods (BAMM) that are site-specific and require approval by the local compliance authority on a case-by-case basis. Typically sites, such as compressor stations, conduct daily Inspection of Watch (IOW's) activities, in which sensory inspections are performed to aide in identifying any abnormal conditions and/or leaks. The IOW's are an effective means for leak detection because the gas is normally odorized with mercaptan allowing operators to identify the leak conditions prior to it becoming of significance. Allowing routine inspections, such as IOW's, as an alternative compliance methodology can significantly reduce compliance costs to industry. EPA has also proposed allowing the utilization of Method 21 as an alternative to optical gas imaging. Though organic vapor analyzers are significantly cheaper than the optical gas imaging equipment, they are not as effective in identifying the location of the leak.

We urge [EPA] to adopt in its final rule the use of alternative methods of compliance instead of a specific technology or survey frequency for sites that are already permitted by the local compliance authority with a different method of compliance for addressing fugitive emissions. EPA's proposed requirements that specify that both the gas imaging methodology and survey frequency may differ significantly from existing permit conditions or state standards. The final rule should provide permitted sources with the option to provide a one-time demonstration proving that the existing method of compliance and fugitive emission limitation(s) in their permit(s) are sufficient to satisfy the stringency and environmental benefit prescribed in the final rule. Any subsequent "modification" or "reconstruction," as defined in the final rule, would trigger a revised demonstration for that source. For those sources with state permits that do not address fugitive emissions from affected sources, or cannot demonstrate to the local compliance authority's satisfaction that their permit requirements satisfy the stringency of the final rule, EPA's proposed federal rule requirements that specify a specific technology and survey frequency for addressing fugitive emissions would then apply.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. We have also finalized a pathway for an owner or operator to apply for an alternative means for emission limitations for a fugitive emissions monitoring and repair program that they believe is equivalent to the final rule's fugitive emissions monitoring program. The application will need to meet the same requirements for an emerging technology AMEL. See section VI.K of the preamble for further discussion.

Commenter Name: Jeff Addington, Manager Air Quality
Commenter Affiliation: Archrock Services, L. P. and Archrock Partners Operating LLC ((individually and collectively, ArchRock)
Document Control Number: EPA-HQ-OAR-2010-0505-6944
Comment Excerpt Number: 7

Comment: In order to focus personnel's time and attention on identifying and repairing leaks, EPA should allow the use of alternative detection methods for both the initial survey and resurveying after any necessary repairs are made. Requiring the use of specialized equipment to resurvey and verify the leak has been adequately repaired would impose a significant burden on our ability to service our customers in a timely fashion. Therefore, we recommend that EPA allow the use of other methods, including soapy water (or Snoop) and combustible gas leak detectors (sniffer testing) to verify the adequacy of the repairs. The benefits of these methods are as follows:

- Snoop testing is simple to perform - it entails placing a soapy water mixture on the area where the leak occurs. If bubbles are visually detected, there still is a leak. This method is not only cost-effective and easy to train technicians to perform, but it is also accurate. It offers a positive validation of the repair and would reduce the time necessary to verify the adequacy of the repair. This test can be performed at a significantly lower cost than coordinating a resurvey using either OGI or a Method 21 device and it is a time-tested, reliable methodology.
- Sniffer testing requires utilizing electronic equipment that emits an audible tone when it detects the presence of leaking combustible gas. Some devices also include visual indicators. The cost of this equipment is substantially lower than the cost of purchasing OGI technology, but its efficacy is equivalent.

Compared to these alternatives, OGI is not a "low cost way to find leaks." Contra 80 Fed. Reg. 56,649. Requiring the use of OGI would be extremely expensive for companies like Archrock that own compressors spread out over a vast area. At the very least, other options, such as Method 21, Snoop testing and sniffer testing should also be allowed for both initial surveys and resurveys.

Response: We are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate. We are not allowing this alternative screening procedure for initial monitoring as its use is limited to certain components as specified within Method 21.

The commenter did not provide enough information on sniffer testing in order for us to make a determination on its use as an alternative work practice, but owners and operators can apply for an alternative means of emissions limitation for technologies that achieve an equivalent level of emissions reduction as the technologies in the final rule. See responses to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2 and DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for information on increased the flexibility regarding fugitive emissions monitoring technologies. Also see the OGI Cost Memo located in the docket (EPA-HQ-OAR-2010-0505).

Commenter Name: J. Roger Kelley, Director, Regulatory Affairs
Commenter Affiliation: Continental Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6963
Comment Excerpt Number: 10

Comment: AVO Should be Allowed in Lieu of LDAR Inspections.

Oil and gas producers have historically and successfully relied on audio/visual/olfactory ("AVO") inspections to detect leaking equipment components. Any leak that cannot be detected in the course of a properly conducted AVO inspection is not significant from an environmental (or health and safety) standpoint. Therefore, an AVO LDAR program consisting of regular inspections and the same level of repair, documentation and recordkeeping requirements presented in OOOOa can be equally effective compared to an Optical Gas Imaging ("OGI")-based program. Furthermore, an AVO-based program is no more susceptible to falsification by unscrupulous operators than is the proposed OGI program.

As a result, the equipment required by an OGI-based program would achieve no benefits greater than those offered by a comparable AVO-based program, and it would achieve no reduction in potential falsification of reports; however, requiring operators to purchase such equipment would clearly inure to the benefit of the manufacturers and distributors of the expensive OGI equipment (e.g., the approximate initial cost of an OGI/FLIR camera is $100,000, an amount which does not include maintenance and certification costs). As is frequently the case, the impact would be felt most heavily by smaller operators.

Response: We disagree with commenter's assertion that leaks that cannot be found through AVO inspections are not significant. In NSPS leak detection and repair rules, such as subparts VV and VVa, AVO is limited to certain pieces of equipment and any evidence of a leak must be confirmed using Method 21. We agree that AVO monitoring in combination with OGI or Method 21 can be an acceptable form of fugitive emissions monitoring but AVO alone is not. The final rule requires owners and operators to maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers a leak through audio, visual or olfactory means, the owner or operator has a general duty to repair these components. We do note that AVO is used to determine defects in combustion devices and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems.

Commenter Name: Cyrus Reed, Conservation Director
Commenter Affiliation: Lone Star Chapter, Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-5418
Comment Excerpt Number: 7

Comment: We also believe requiring use of the best equipment (such as gas infrared cameras) for both initial surveys and re-surveys could help reduce substantially methane and co-pollutant emissions from leaking equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Anthony J. Ferate
Commenter Affiliation: Oklahoma Independent Petroleum Association (OPIA)
Document Control Number: EPA-HQ-OAR-2010-0505-6810
Comment Excerpt Number: 4

Comment: The current NSPS OOOO is a relatively new regulation that has brought substantial benefit to the environment. We do not believe EPA should propose changing the Leak Detection and Repair (LDAR) requirements from monthly Olfactory, Visual and Auditory (OVA) checks to monthly checks plus Optical Gas Imaging (OGI) without determining the environmental benefit of the additional monitoring. Based on information from its members, OIPA believes that the vast majority of the leaks at oil and gas sites are detected using OVA. EPA should compare the cost of OGI versus traditional OVA or Method 21 surveys to determine if the additional cost has a substantial environmental benefit.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6963, Excerpt 10.

Commenter Name: Peter Roos, Chief Executive Officer,
Commenter Affiliation: Bridger Photonics, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6164
Comment Excerpt Number: 1

Comment: Bridger Photonics, Inc. wishes to alert the EPA to new methane detection and imaging technology that is under development at our company and funded by the DOE. We are developing optical gas imaging (OGI) technology that is based on laser wavelength modulation spectroscopy rather than the traditional infrared camera OGI.

Response: The EPA thanks the commenter for the information that was provided. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

EPA-HQ-2018-001886 3/2/2018 ED_001544_00002162-00178

Commenter Name: Dr. Anish Goyal, Vice President, Technology
Commenter Affiliation: Block Engineering
Document Control Number: EPA-HQ-OAR-2010-0505-6213
Comment Excerpt Number: 6

Comment: Finally, we want to inform the EPA of new technology based on mid-infrared spectroscopy using quantum cascade lasers. Block Engineering manufactures two gas detection systems called LaserSenseTM and LaserWarnTM. Both of these instruments are suitable for the detection and identification of many HAPs whether alone or in mixtures. The LaserSenseTM is suitable for use according to Method 21. The LaserWarnTM is a laser-based open-path atmospheric sensor for fenceline monitoring. Table 1 gives the calculated sensitivity of both LaserSenseTM and LaserWarnTM. The measurement time for both of these instruments is about 1 second.

Response: The EPA thanks the commenter for the information that was provided. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Jason Amsden, Research Scientist and Vikram Rao, Executive Director
Commenter Affiliation: Duke University Nanomaterials and Thin Films Lab and RTI International
Document Control Number: EPA-HQ-OAR-2010-0505-6240
Comment Excerpt Number: 3

Comment: The ARPA-E MONITOR program is aimed at developing low cost methane detection solutions that will result in a 90% reduction in methane emissions over the course of a year. As part of this program, Duke University, in collaboration with RTI International are developing a miniature mass spectrometer. Mass spectrometry is the gold standard for chemical analysis and mass spectrometers are used in many aspects of the oil and gas industry such as in characterization emissions monitoring, and oil spill tracking. The main factor that has up to now prevented the widespread use of mass spectrometry in fugitive emissions monitoring is the size, weight, power, and capital cost of mass spectrometers. Over the past 15 years, numerous advances have been made in mass spectrometer miniaturization. However, miniaturization of magnetic sector and linear quadrupole mass filter type mass spectrometers, which are the most useful for methane and volatile organic compound detection, involve a tradeoff between throughput and system resolution resulting in poor performance. Recently, a solution to the resolution vs. throughput tradeoff has been shown for magnetic sector mass spectrometry using aperture coding and computational spectroscopy paving the way for drastically improved performance in a miniature mass spectrometer. ARPA-E as part of the new MONITOR program has funded the development of a miniature mass spectrometer based on aperture coding for both methane and VOC detection. The miniature mass spectrometer will have advantages over currently used methane and VOC detection technologies, require limited qualifications for operation, and cost significantly less per year to operate.

The miniature mass spectrometer under development has several key advantages over optical gas imaging (OGI) and method 21 sensors discussed in the proposed rule. First, the miniature mass spectrometer can measure both methane and VOCs with a single unit. Separate detection systems are not required. Furthermore, miniature mass spectrometers can easily differentiate and identify the composition of the gas. This leads to thermogenic and biogenic differentiation ability and a lower false alarm rate. Second, the sensitivity of the mass spectrometer will be orders of magnitude better than method 21 and OGI. For example, mass spectrometers have a sensitivity to methane and VOCs down to parts per billion concentrations. Third, taking a measurement with a mass spectrometer will take less than 30 seconds and it will have the ability to measure continuously. It will be hand-held and transportable to any location for any period of time.

Operation of the mass spectrometer will not require an advanced degree and rely significantly less on the skill of the operator than techniques like OGI. Sophisticated data processing algorithms will be included with the mass spectrometer that will provide a leak/no-leak alarm with leak species identification similar to ion mobility spectrometers and mass spectrometers used at security checkpoints. Furthermore, it will have similar calibration requirements to method 21, so operators will already be familiar with calibration procedures. Finally, the mass spectrometer will transmit the raw data off-site for further analysis and increased data security and when combined with leak localization algorithms, be able to run continuously on site independent of any operator and send data about potential leaks to a central location.

Finally, we estimate the cost of the unit to operate per site per year will be on the order of $10,000 – significantly cheaper than OGI based leak detection technologies. Initial prototypes for field testing will be ready at the end of the ARPA-E MONITOR program (2-3 years).

Response: The EPA thanks the commenter for the information that was provided. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Josephine Chang and Hendrik Hamann
Commenter Affiliation: IBM T.J. Watson Research Center, Intelligent Multimodal Methane Management Solution (AIMS)
Document Control Number: EPA-HQ-OAR-2010-0505-6445
Comment Excerpt Number: 1

Comment: In Docket # EPA-HQ-OAR-2010-0505, the EPA requested comments on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future.

IBM is developing An Intelligent Multimodal Methane Management Solution (AIMS) which will use a ground-based sensor network to enable continuous fugitive emissions management for remote oil and gas infrastructure. Compared to standard suggested practice for methane leak detection and repair (LDAR), which involves yearly, biannual, or quarterly site visits to search for and repair leaks, a smart, real-time remote monitoring solution such as AIMS has the potential to prevent a massive amount of air pollution and revenue loss if it can be implemented at the proper cost point. AIMS is a complete methane leak management solution which will feed data from a network of ground-based sensors into a collection of advanced analytics algorithms. System design, sensor placement, and sensor operation will be dictated by optimization routines which consider customer input detailing site layout, location of likely leak points, and location and timing of intentional methane emission events. Other information such as local topography, vegetation, and historical wind and background methane conditions will also be taken into account. This site-specific information will be used to determine proper sensor density and placement, define minimum sensor sensitivity, and inform leak detection and sensor monitoring protocol during operation.

Response: The EPA thanks the commenter for the information that was provided. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 22

Comment: Other technologies are emerging in the detection of fugitive emissions that should be authorized by the rule. The Journal of Petroleum Technology recently identified a number of technologies that have a number of advantages, as indicated below: (http://www.spe.org/jpt/article/8437-pressure-to-reduce-methane-emissions-highlights-the-need-for-better-monitoring/).

- **Better components.** Maxion Technologies is working on producing an affordable, laser light source that sends out light at a wavelength (3.3 μm) that is far more effective for imaging methane gas than the ones commonly used (1.6 μm), which were designed for the communications industry. The challenge is to lower the high cost of making a better laser for a small group of users.
- **Cheaper, smaller, and quantitative.** Bridger Photonics is working on using light detection and ranging (LIDAR) to rapidly create 3D images to identify the location and size of methane concentrations at a lower cost than what is on the market.
- **Constant surveillance.** Palo Alto Research Center (PARC) is working on a chemical detector on a chip using a nanomaterial whose electrical resistance changes when exposed to hydrocarbons. Its goal is to create a tiny sensor on a chip that can be cheaply produced with printing methods used for making microchips.

Response: The EPA thanks the commenter for the information that was provided. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 14

Comment: On page 115, "the monitoring plan must also include a description of how OGI surveys will be conducted." I can continue with quotes, but the main issue with OGI is angle of sun, wind, and ambient temperature differentials. It's not an easy technology to use. We own and operate our own FLIR camera, and the least size that you can see, it's got to be huge. I mean, here in the report, page 239, "EPA's recent work with OGI indicates that fugitive emissions at concentrations of 10,000 ppm are generally detectable using OGI instrumentation."

Now, 10,000 ppm levels represent in our business enormous leaks. Now, in a study finding by the AAGL and DOD (phonetic), leaks were detected down to the 4 ppm level. With our technology -- here's a quote from that report. "It is remarkable that a 4 ppm methane plume could be detected by a helicopter at a 50 meter altitude."

And finally, page 322, "the EPA is proposing the use of OGI as a low cost way to find leaks." Low cost versus aid (phonetic), a limited sampling of available technologies in my opinion. Again, the proposal did not include a large number of available technologies with fugitive emission detection, rather it seemed to compare Method 21 technology versus OGI. That's all I have. Any questions from you?

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 104

Comment: And so what I want to talk about is some of the regulations currently, and there's a lot of discussion on the OGI, the optical gas imaging camera. There was a gentleman earlier with FLIR. We also have an optimal gas imaging camera. There are several other ones that are out there on the market, as well.

It is a valuable tool, however, it's not the only tool. There are a number of tools out there, and I just call it a tool in the toolbox. There's different applications depending on what type of facility you're inspecting, aboveground facilities, below-ground piping. There's a number of different things, so there's various tools. To try to fit one tool -- to say that one tool is the answer to everything I think is a mistake.

Some of it goes back to the Method 21 technology and, yes, there are Method 21 leak detection technologies. That rule was generated, you know, several years ago; and even since that rule came out, there's a number of different technologies, laser-based, optical-based, that were never developed during Method 21 days, and so what I -- what I hope is in the regulations, and I'll provide this written, as well, proposing some of the other technologies that are cost, price -- you know, some gentlemen talked about the cost, that it's going to cost some of smaller operators and stuff.

There's tools that can go down to several thousand dollars on up to $100,000 and everywhere in between. There's vehicle-mounted applications. There was a girl that spoke from Rebellion about a fixed system. There's aerial systems. We're working on drone-based systems right now, so I hate to see the regulation come out prescriptive to just the OGI camera because I think -- I think that's a big mistake. There are scenarios even with an OGI camera, depending on ambient temperatures, gas temperatures, and things of that sort where it can actually not see a leak, so I just would hope that some of these other considerations are taken of different technologies.

Now, when I write with the submissions, I'll kind of describe some of the other technological advances that are out there being worked. We work a lot with DOT, SIMNSA, and some other regulatory environments, not in the mid- and upstream like we're talking about here, but more on the downstream and LDC gas operations, and there's different technologies in that marketplace, too. We also develop -- you know, there's a lot of talk now with, you know, determining the quantification of the leaks, as well.

There's a lot of tools that are out there that can do that as well as other devices which we work with like the high-flow sampler and other things there. But I'll run down the different technologies that are out there and the other platforms and I would hope you would consider some of these instead of just kind of being prescriptive to one -- one technology out there. Thank you.

In response to a question about the term optical gas imaging and if there are a variety of technologies that the commenter would consider to fit those three words, the commenter indicated that: Yes. In fact, a while back, some of the -- before Quad O and some of the subpart W types, the EPA actually came out with some language they called the optical illuminating device, which is not an optical gas imaging camera. It's really the wrong nomenclature for it, but there are laser-based technologies out there today. We manufacture a number of laser-based technologies that are about a fifth of the cost of an -- of an optical gas imaging camera, and there are literally thousands of them used around the world every day performing leak detection surveys.

And so the language, the way it's written now, it's not a Method 21 tool and it's not an optical gas imaging camera; therefore, that particular tool can't -- right now doesn't meet the regulations to be used, yet they're out there every day finding thousands of leaks out there in a day at a cost of about a fifth of what an optical gas imaging camera is.

And I'm not shooting down an OGI camera. We actually have one ourselves that I mentioned earlier. There's applications for that, but it's not an application for everything. It really depends on the facility -- the type of facility, the type of leaks you're looking at, and so forth.

Response: The EPA is encouraging innovative technologies and leak detection approaches. With respect to the Rebellion technology or other multi- or hyper- spectral imaging instruments, please see response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 42. We have also revised the requirements for walking path to observation path.This should alleviate the need for an alternative monitoring plan or alternative means of emission limitation for the use of drone based OGI instruments as long as the drone based OGI system still meets all the requirements of the rule. Other drone based technologies that for example produce results such as a path averaged concentration must apply for an alternative means of emissions limitation. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Anthony J. Ferate
Commenter Affiliation: Oklahoma Independent Petroleum Association (OPIA)
Document Control Number: EPA-HQ-OAR-2010-0505-6810
Comment Excerpt Number: 6

Comment: OGI instruments require specialized training to operate correctly. Standoff distance, wind, and temperature can impact the method detection limits. OGI instruments are unsuitable during high wind events, which occur with some frequency in Oklahoma. EPA should offer monitoring alternatives were OGI is unsuitable due to adverse conditions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2 regarding the use of Method 21. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Henri Azibert, Technical Director
Commenter Affiliation: Fluid Sealing Association (FSA)
Document Control Number: EPA-HQ-OAR-2010-0505-6754
Comment Excerpt Number: 13

Comment: Partly in response to the comment solicitation on an alternate option for the fugitive emission monitoring program (page 278), we would like to suggest that training be used as part of the remediation once leakage is detected above a certain level. The proposed regulation increases the frequency at which the equipment needs to be surveyed when a certain level of equipment leaks are detected, (below 1%, 1 to 3%, and above 3%). Given the random nature of leaks, and that a few component at a site can account for the majority of emissions, training on leak detection and repair should occur on a frequent basis. Accredited training programs should be included as a remedial step in addition to the change in monitoring frequency.

Response: In the final rule, the EPA requires that records be maintained that document the training and experience of the operator conducting the survey. We do not believe the final rule should specify training criteria for those personnel surveying or repairing sources of fugitive emissions but expect that owners and operators will develop training programs for personnel that will be incorporated into their monitoring plans. There are far too many brands and types of OGI and Method 21 for the rule to specify training requirements. Similarly, there are far too many types of components and equipment configurations in the field for the rule to specify specific training requirements. We believe that each owner or operator should determine and implement the training that is appropriate for their specific well sites, compressor stations and instrumentation.

Commenter Name: Dayle McDermitt, Vice President, Research and Development
Commenter Affiliation: LI-COR, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-5413
Comment Excerpt Number: 2

Comment: If the EPA strives to minimize emissions in the oil and gas sector, the highest level goal should be to identify, locate and repair GHG and VOC leaks as quickly as possible. Continuous monitoring systems are, by definition, designed to continuously monitor a location for targeted emissions, and are best suited to identify and quantify leaks as soon as they occur.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 32

Comment: We do not believe that other techniques should be used as part of the survey process, such as visual inspections, signs such as staining of storage vessels, or other indicators of potential leaks or improper operation. We believe that these “other techniques” are not quantitative and objective such as OGI or EPA Method 21 and will create unnecessary repair and resurvey work for owners and operators. We believe that these additional requirements do not add value to the survey process. Visual inspections may identify staining as a potential leak, but the owner / operator may have corrected the leak in the past and decided not incurred the cost to address the stain that was left behind.

Response: We appreciate the commenter’s input on this issue. The final rule requires owners and operators to maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers a leak through audio, visual or olfactory means, the owner or operator has a general duty to repair these components.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 15

Comment: Number one: I encourage the EPA to develop effective regulations based on the sampling performance standards and not be limited to any particular methods for sampling, such as the proposed IR imaging cameras and the possible use of the Method 21 technology.

Response: Owner operators are given the flexibility to choose OGI, Method 21 and the variants within those categories. Additionally, see response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 11

Comment: My comments focus on the fact that optical or OGI, optical gas imaging, is, really, the only method identified in the rule for reducing methane emissions, and I have a bunch of quotes from the proposed rule, page 17. EPA is "proposing that new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) conduct fugitive emissions surveys semiannually with OGI."

Now, OGI and Method 21 alternatives are the only options listed in the proposed rules. These proposed rules under the proposal seems to single out a small number of companies. There are many other alternatives that can -- that can find fugitive emissions. Some of these alternatives with LIDAR, TDLAS systems, these alternatives, due to the use of active illumination of hydrocarbons, can detect much lower levels of fugitive emissions.

Again, on page 106, "we solicit comments on whether to allow the EPA -- the EPA Method 21 as an alternative to OGI" monitoring. Why not mention all of the other, I think, more effective technologies that are out there for finding methane emissions?

Response: Please see response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for discussion on other technologies/systems, such as tunable diode laser absorption spectroscopy. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 58

Commenter Name/Affiliation: W. Michael Scott, VP / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 56

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 57

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 60

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 59

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number 56

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number 60

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 23

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 8d

Comment: Rather than allowing operators to continue to experiment with methods of finding and repairing leaks, the Rules limit operators to a single form of compliance: OGI technology.

Response: The final rule has provided more flexibility by allowing Method 21 as an alternative to OGI monitoring. We evaluated Method 21 and concluded that a repair threshold of 500 ppm, it provides at least the same emission reductions as OGI. Additionally, the final rule includes a pathway for approval of emerging or innovative technology. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

4.6 Initial Monitoring Survey

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 4

Comment: 30 day deadline for testing after completion or modification (pages 106 and 112)-We suggest EPA consider a 45 day window to schedule and complete the initial leak testing. This will allow operators more flexibility to efficiently schedule contractors.

Response: We received a wide variety of comments and suggestions for the appropriate time for fugitive emissions monitoring to begin. Based on these comments, we believe that for well sites the startup of production (i.e., the initial flow following the end of the flowback when there is continuous recovery of saleable quality gas) more accurately reflects the start of normal operations and would capture any fugitive emissions from the newly constructed or modified components at the well site. Therefore, we are finalizing that the startup of production marks the beginning of the initial monitoring survey period for the collection of fugitive emissions components at a well site. The initial monitoring survey must take place within one year after the date of publication of the final rule in the Federal Register or 60 days after startup, whichever is later. See section VI.F.1.g of the preamble to the final rule for more information regarding this issue.

For compressor stations, we initially proposed a 30-day period after startup to conduct the initial monitoring survey. In order to account for several situations as detailed in section VI.F.2.f of the preamble to the final rule, we are allowing a period of one year after the date of publication of the final rule in the Federal Register or 60 days after startup of the compressor station, whichever is later, to begin the initial monitoring survey.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 16

Comment: Finally, after the rule goes into effect, the going-forward requirement to conduct a survey of fugitive emissions within 30 days is incompatible with typical industry practices. 30 days after the first well completion or modification, operators are typically still evaluating the well, and it is not feasible or practicable to conduct an initial survey of fugitive emissions at that point. Operators typically need more than 30 days to even evaluate the well and understand all the equipment that will be on site. NDPC therefore requests that EPA allow more time before initial monitoring of fugitive emissions is required. NDPC proposes that the initial survey be required within 90 days of well completion. This time period is consistent with the well registration schedule in North Dakota, which requires that operators file a well registration within 90 days of well completion. Synchronizing these requirements would allow operators to combine the fugitive emissions survey with the site registration field visit, which operators often perform as part of their best practices.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 13

Comment: Initial Monitoring Survey Point: As currently written, the initial LDAR survey is to be performed within 30 days of well activation. This timeframe is much too short in all instances within the oil and gas production industry. Instead, Apache recommends a 90-day time period to complete the initial survey. This is much more realistic considering the time and logistical capacities of oil and gas field crews plus potential limited availability of monitoring contractors.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 26

Comment: USEPA solicits comment on whether thirty (30) days is an appropriate period for the first LDAR survey following startup of production or modification. As USEPA is aware, the oil and natural gas exploration industry has undergone a revolution with regard to the manner in which it searches for and produces energy for the nation. The use of multi-well pads is just one way in which Antero develops our natural resources in an efficient manner, which results in the production of energy while also limiting its environmental impact. By drilling multiple wells from one location as opposed to multiple wells from differing locations, Antero limits its overall footprint in the environment. This innovation though, affects Antero's ability to initiate its first LDAR survey.

Safety concerns associated with the presence of temporary equipment at well sites will make it impractical to survey all fugitive emissions components within thirty (30) days of any well completion because, other wells are often drilled and completed within that time frame. In addition, because most well pads include multiple wells, the period between drilling the first well and the last permitted well is often significantly longer than thirty (30) days. These are active production sites, therefore, there are serious safety concerns associated with conducting LDAR surveys during active well completions.

Antero would propose that USEPA consider the standard currently contained in the Ohio Environmental Protection Agency's General Air Permit for Oil and Gas Well Site Production Operations (General Permit 12.2) that requires the initial survey be performed within ninety (90) days of startup of production. The proposed time frame contained in the Ohio General Permit provides a more realistic time frame to perform an initial survey without potentially resulting in safety issues while initial oil and gas production and completion activities are taking place on the well pad.

Further, Antero understands that an overriding goal for any regulatory framework is a measure of consistency where practicable amongst the varying regulatory agencies. To further this goal, as suggested by USEPA at 80 FR 56595, and for the other reasons articulated above, Antero suggests that the appropriate timeframe for conducting an initial LDAR survey is within ninety (90) days following startup of production or modification.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 16

Comment: Hess proposes that the Proposed OOOOa Rule: 1) require the initial fugitive emissions survey to be conducted within 90 days of well completion.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 22

Comment: With respect to implementation of LDAR and initial monitoring surveys within 30 days of well completion, operators are typically still evaluating wells at that time and need additional time to fully consider emissions, develop the site, and understand all the equipment that will be present. Construction may not yet be complete nor production started. The initial 30 days is an evaluation period for storage vessel applicability, and controls do not require installation until 60 days. EPA does not provide support for the 30 day requirement, which significantly shortens the 180-day period currently required for similar programs such as NSPS KKK and OOOO. Following startup of a new well site or compressor station, operators need sufficient time to carefully verify proper operation of new equipment installations. Furthermore, 30 days is not a sufficient time to coordinate with and engage necessary third-party consultants who would conduct leak detection at most facilities. Initial survey scheduling should be allowed sufficient time to be integrated with the existing field or area wide survey schedule to allow the most effective and efficient use of equipment and manpower required for these surveys.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 11

Comment: To the extent EPA proceeds with a comprehensive leak detection regulation instead of DI&M, the initial monitoring survey under any such fugitives leak detection program should be initiated within 180 days after initial startup (rather than the proposed 30 days), which is the standard approach in comparable NSPS programs, including Subparts KKK and OOOO.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 51

Comment: EPA proposes that the initial monitoring survey be completed within 30 days of startup of a new or modified affected facility. EPA provides no real support for this 30-day time period, particularly given that other similar programs, such as NSPS KKK and NSPS OOOO (where leak detection is currently imposed at natural gas processing plants) allow for 180 days before the first leak survey needs to be completed. Allowing initial inspection to occur within 180 days from startup of a new compressor station or well site facility provides owners or operators time to do a thorough check of all new equipment installations before the survey. In addition, industry typically uses third-party contractors to conduct leak detection at many facilities. In most cases, more than 30 days would be required to coordinate engagement of and implementation by a third-party consultant.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 19

Comment: EPA is soliciting comment on whether 30 days is an appropriate period for the first survey following startup or modification. EPA is co-proposing monitoring surveys on an annual basis for new and modified well sites.

- CONSOL feels that an appropriate period of time for the first survey following startup or modification at well sites and compressor stations would be 180 calendar days. This would be in-line with the LDAR initial monitoring requirements of the Pennsylvania Department of Environmental Protection (PADEP). When systems and components at well sites and compressor stations are initially installed, prior to startup, they undergo integrity testing and testing of their functionality, such as hydrostatic pressure testing of pipelines. Based on our experience, a leak is unlikely to be encountered prior to six months after startup. Leaks are more likely to be encountered six months to two years after initial startup or modification due to pressure differentials and temperature extremes related to continued use.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 126

Comment: Requiring An Initial Survey Requirement Within 30 Days Of Completion Is Not Appropriate For A Number Of Reasons

§60.5397a(f)(1) You must conduct an initial monitoring survey within 30 days of the first well completion for each collection of fugitive emissions components at a new well site or upon the date the well site begins the production phase for other wells. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 30 days of the well site modification.

There are numerous problems with this requirement both in the language chosen to describe the requirement as well as the unique technical issues that arise as a result of trying to define a well site as something other than a surface site with a well. First, within 30 days of first well completion is inappropriate, as production doesn't always begin immediately after a well completion if for example gathering infrastructure is not yet available or construction of production facilities such as storage vessels, separators, heaters and control devices are not yet complete. There may also be use of temporary equipment because of well flow problems while trying to startup production or while permanent facility construction is being completed. Instead this requirement needs to be tied to the startup of production to be consistent with other requirements in the rule such as for storage vessels.

Within the first 30 days of startup of production, production rates for wells are evaluated to determine whether any storage vessels will be affected facilities. If so, control devices are required to be constructed and operational within 60 days from startup. As well, the first 30 days may exempt a wellsite altogether if production is less than 15 BOE/day. The point is that the first 30 days of production is an evaluation period for applicability of requirements the second 30 days is allowed to complete construction of any required emissions control and closed vent system. And that is for true well sites with wells. The problem gets more complex by including central tank batteries in the definition of a wellsite rather than having its own definition as being part of a central production site that we recommended in Section 27.2.12.

Consider this realistic scenario. An operator wants to develop a new field of 20 wells that are planned to be drilled in succession, with potential plans to drill more. It is determined that it makes sense to construct a central tank battery that will become defined as a well site upon first production that will grow in size as each new well begins production and is aggregated to the central tank battery wellsite. The central tank battery is completed to enable startup of production of the first well with a capacity to eventually handle all 20 wells. After startup of the battery, semi-annual leak monitoring is required within 30 days and is completed and leaks repaired. Shortly thereafter, the second well comes online and starts production to the central battery well site, and is a wellhead only site. Now, according to §60.5397a(f)(1), the central battery must be surveyed again a month after the initial survey because of the new well. This time no leaks are found. This 30 day monitoring pattern continues until all 20 wells are completed and will continue if more wells are immediately added or first wells are refractured for any reason. The wellhead only sites are also monitored each time since they are part of the central battery well site.

The point of the scenario is that the wellsite definition is not workable in terms of the how the initial monitoring requirements have been designed in this proposal. Instead of monitoring a central tank battery initially, then semi-annually, to hopefully annually as currently conceived in the proposal, the central production site and all wells tied into it will have to undergo monitoring at an unpredictable frequency based on changes that don't occur at the battery but rather wells tied into it. The battery will always require initial well monitoring as will all the wells tied to it within 30 days each time a new well is added or refracture occurs at an existing well. This is overly burdensome and costly. Again, API recommends dissociating central batteries from the well site definition to avoid this situation.

Instead of 30 days, the time period for the initial survey should be within 180 days after startup of production to allow sufficient time for completion of construction and the startup period, and scheduling the new site into the area leak detection plan. After the initial 60 days to complete construction of the control device, an additional 120 days should be allowed to work monitoring of the well into the next scheduled monitoring period that would include all the wells in the area. Calling out a contract crew to monitor one remote well site, when in a matter of a few weeks or couple months they may already be scheduled to monitor an entire area is not a cost efficient use of manpower. Such inefficient use of resources could put undue pressure on availability of crews for all operators.

Suggested regulatory revisions are provided at the end of this section (see Section 27.4.14).

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4. In the final rule, we have modified the well site definition as follows, "for the purposes of fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries)." We are also further clarifying the boundaries of a well site for purposes of the fugitive monitoring requirements. Our intent is to limit the oil and natural gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant. Therefore, the collection of fugitive emissions components within this boundary are a part of the well site.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 24

Comment: EPA should delay the initial survey from 30 days to 180 days to ease integration into the survey schedule for surrounding applicable sites.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 12

Comment: In the proposed rule, EPA has established requirements to conduct the initial monitoring survey within 30-days for new or modified well sites and compressor stations. SWN supports the initial monitoring survey as it essentially serves as the "performance test" typically required of controls under NSPS standards. We also believe the initial monitoring survey helps assure safe operating conditions at a new/modified well site or compressor station. However, we believe that the timeline to conduct the initial monitoring survey should follow a similar "within 60 days but no later than 180 days upon commencing operation" timeline for testing control devices under other NSPS standards.

Allowing the initial monitoring survey within these timelines (60-180 days) also allows companies to coordinate the initial monitoring survey for new/modified well sites and compressor stations such that several sites can be surveyed in "aggregate". This allows for better efficiency in deploying monitoring survey teams (whether internal or third patty) and helps lower the cost of conducting the monitoring survey (as mobilization cost to survey a single site can be as expensive as the mobilization cost to survey several sites). In addition, providing this expanded timeline helps address issues associated with conducting monitoring surveys in areas with inclement weather.

Recommendations:

We also recommend that EPA revises the 30-day time line to conduct the initial survey to at least 60 days and possibly up to 180 days (to minor EPA NSPS testing timeframes and allow the coordination of aggregated well site/compressor station site surveys as opposed to "singular" surveys).

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 41

Comment: In numerous instances in the proposal, EPA introduces substantial and burdensome initial survey requirements:

EPA appropriately solicits comment on whether 30 days is an appropriate period for conducting an initial survey and initiating fugitive emissions monitoring. TXOGA believes that 30 days is not appropriate. These requirements will be costly, the time constraints will overwhelm operators, and will prove impractical.

As an initial matter, the proposed rule does not provide a definition of “the end of” a well completion or the date the site “begins production.” These omissions are important because, as written, the rule does not take into account the fact that wells may be shut in temporarily after completion. Nor does it account for the extended flow back period a well may undergo, during which crude oil may be produced to a flowback separator or test separator for a long period of time.

Moreover, the 30-day timeline for conducting an initial survey will not capture that facility’s emission profile. This is because production and equipment is often phased in. Similarly, startup may be delayed beyond this 30-day period. Further, construction may not be completed within 30 days given that production is evaluated within the first 30-days of startup to determine whether any storage vessels will be deemed affected facilities and the 60-day window to install a control device, if needed.

We also note that facilities that are ramping up production may install new wells at regular intervals and this 30-day requirement will become extremely costly and result in unreasonable inspection intervals. For owners or operators actively adding well sites, site surveys will necessarily take place at a high frequency – potentially at less than 30 day intervals. The initial survey requirements are compounded by requirements that initial surveys be conducted for tank batteries when those are added. At the same time, area-wide surveys will be conducted that should capture the same information. These requirements seem to be duplicative. Facilities should be able to maintain regular monitoring schedules to avoid the cost of surveying individual well sites on a piecemeal basis when regular area-wide surveys are already being conducted that will capture these same emissions.

Accordingly, EPA needs to base the initial survey on a sufficient period of time after the startup of production. It should not be based on the date of well completion. As a general matter, the period of time for completion of initial surveys and commencement of fugitive emissions monitoring of new or modified well sites and compressor stations should be no less than 180 days after the date of startup or within 180 days after the date a modified affected facility begins operation. Initial surveys of new or modified well sites and compressor stations should not be required any sooner than 180 days after the date of startup or 180 days after the date a modified affected facility begins operation. Over time, as this rule continues to be in effect, 180 days for initial monitoring also helps integrate the new or modified site into the existing schedule for scheduled monitoring for other wells in the area. It will take unnecessary and costly extra resources in equipment and manpower to require initial 30 day monitoring for every new well, when area-wide scheduled monitoring for other sites already subject to leak detection requirements may be set to occur a short time period afterwards. It is more efficient to work new wells into an existing monitoring schedule, than to have randomly occurring monitoring for single new sites.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Matthew D. Hall
Commenter Affiliation: Consumers Energy Company
Document Control Number: EPA-HQ-OAR-2010-0505-6862
Comment Excerpt Number: 8

Comment: At multiple points in the proposal, EPA requests comment on the appropriate time for an owner of operator to conduct initial fugitive emissions monitoring for an affected unit. EPA proposes a 30 day period after start up in the majority of cases. Consumers Energy requests a startup delay for leak surveys to not be less than 180 days. As noted in the AGA comments package, EPA should make the effort to align this proposal with existing regulations wherever possible. NSPS Subpart JJJJ, covering spark ignition engines, requires initial performance obligations 180 days from starting up.

Consistency in EPA regulations allows operators to more efficiently implement compliance programs as well as reducing costs, thus providing saving that are passed on to our customers.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)
Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 10

Comment: EPA's Proposed Compliance Timeframes are Too Short

The industry currently relies on audio, visual and olfactory ("AVO") inspections and only recently began exploring advanced leak detection technologies. Therefore, we believe the proposed regulations for methane and VOCs do not provide companies with a sufficient timeframe to achieve compliance. To satisfy the EPA's proposed LDAR requirements, EPA should allow companies more time for planning and implementation beyond the proposed period.

Further, EPA should increase the initial survey timeframe requirement to 90 days and the repairs requirement to at least 30 days, instead of the insufficient and unworkable timeframe of 30 and 15 days. At a minimum, EPA should provide for a mechanism to allow a "variance" or hardship extension of the time frames when extenuating circumstances are present.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: J. Jared Snyder
Commenter Affiliation: New York State Department of Environmental Conservation.
Document Control Number: EPA-HQ-OAR-2010-0505-6894
Comment Excerpt Number: 8

Comment: EPA requested comment on whether initial surveys could be conducted within 30 days of site modification for well sites and compressor stations for the purpose of fugitive emissions standards. The DEC agrees that 30 days is a reasonable timeline.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 31

Comment: The requirement to conduct an LDAR surveys for affected facilities using OGI technology within 30 days of the well completion or within 30 days of modification is overly restrictive.

As stated previously, many affected facilities in Pennsylvania will be small business entities that will rely on contractors to provide OGI LDAR monitoring services. In an active drilling environment, PIOGA believes that LDAR contractors will be in high demand and may give scheduling preference to "larger" clients versus small business entities. To provide schedule flexibility and to be consistent with existing Pennsylvania LDAR requirements, PIOGA suggests that a 60 day requirement. EPA also solicited comment regarding the proposed 30 day requirement to conduct an LDAR survey following site modification. As noted, PIOGA believes that a 60 day requirement is more appropriate.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 27

Comment: The proposed LDAR compliance date is unreasonable

Proposed 40 C.F.R. § 60.5370a(a) requires compliance within 60 days after publication of the final rule in the Federal Register. This is not feasible, realistic, or reasonable. One of the most difficult aspects of implementing a new LDAR program is the time required to set it up. This includes tracking systems (databases), allocating or hiring personnel, and conducting training. Sixty days is not even close to sufficient time for operators to perform these tasks for hundreds if not thousands of facilities. In addition, as experienced in Colorado, there may not be sufficient, trained third parties available to implement these programs in certain areas. There will be numerous operators (or contractors) that will have to invest in new monitoring equipment. Lead time alone for ordering monitoring equipment, such as OGI, is, itself, approximately 60 days. When Subpart OOOOa is finalized, this will likely increase the lead time based on increased demand for such instrumentation by operators. When Colorado finalized its LDAR requirements in Regulation 7, CDPHE allowed nearly 8 months for operators to begin LDAR monitoring using Approved Instrument Monitoring Method. As with the storage vessel requirements under the original NSPS OOOO, MarkWest recommends revisions to the rule include reasonably sufficient implementation time, and suggests 9 to 12 months as a reasonable implementation timeframe.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 40

Comment: The initial implementation of the regulation will require training and startup time (including obtaining approval of corporate leak detection programs as discussed above. Accordingly, it is important for EPA to provide an initial one-year phase in of these requirements. This will allow companies to obtain equipment, train personnel, and obtain appropriate contractors. Absent this phase-in, the rule will not be achievable and will fail the BSER test.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Bill Thompson, Chairman
Commenter Affiliation: National Tribal Air Association (NTAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6705
Comment Excerpt Number: 7

Comment: The Proposed Rule provides that an initial survey of fugitive emissions components (*e.g.,* closed vent systems, connectors, open-ended lines, pressure relief devices, thief hatches on tanks, and valves) for a well site or compression station would need to be conducted within 30 days of the site's or station's startup or modification.

The NTAA finds, as too long, the time allowed to conduct an initial survey, particularly since a primary purpose of the Proposed Rule is to limit the amount of fugitive emissions of methane and VOCs released by oil and natural gas facilities into the atmosphere. The Clean Air Act requires industrial facilities to implement a leak detection and repair programs to control fugitive emissions of VOCs. When repairs to such facilities have occurred, EPA has historically allowed owners and operators to resurvey the repairs within 15 days of their completion to ensure that the repairs have been successful; EPA has found the timeframe to be sufficient.

The NTAA recommends that the Proposed Rule require an owner or operator of a well site or compressor station to conduct an initial survey of fugitive emission components within 15 days of the site's or station's startup or modification.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 42

Comment: We believe that 90 days is a reasonable time period to complete the first survey following startup or modification of a well facility. After we start production at a well facility, we have several items to complete prior to closing out the drilling project such as land restoration, installing pumping and chemical injection equipment, and installing flow lines to a tank battery. 30 days after start-up may be a reasonable time period in a refinery or chemical plant because most of the construction is complete at state-up. Our project schedule does not follow the same structure as refineries and chemical facilities.

We request that EPA clarify that the Deliverable from this survey is only the OGI imaging and any associated repairs, and not the OGI imaging and reporting. If reporting is included in the designated time period, we believe that additional time will be required to survey, receive and process data from the survey, develop reports, review reports, and, if necessary, transmit to the regulating agency.

EPA is also suggesting that a third-party company perform all of the survey work to maintain independence in reporting. We can see two potential issues complying with the 30 day survey requirement if third-party inspectors are required to complete the work. The first issue is short term, we do not believe that a sufficient number of third-party survey companies will be available to complete the work due to the uncertainty of the regulation discussed above. The second issue that we can foresee is that the regulated parties do not have direct control over the third-parties like we have with our own employees. Third-party companies are not required by this regulation to complete the survey work within 30 days, which may result in different priorities than the regulated party. The regulated party will receive any penalty from late reporting, not the third party that is only responsible for survey activities.

Response: Concerning the time period for beginning the initial comment period, see response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

There are specific requirements for what is to be included in the annual report in §60.5420a(b)(7) for fugitive emissions monitoring. The initial annual report is due within 90 days after the end of the initial compliance period and each subsequent report is due the same date each year as the initial annual report.

We agree that the availability of trained OGI contractors may not be sufficient in the short term after the rule becomes effective. Therefore, owners/operators that have constructed, modified or reconstructed a well site or compressor since the proposal date of the rule up to one year after the publication of the rule must perform their initial monitoring survey by one year after the rule's publication date or within 60 days of the startup of production, whichever is later. Owners or operators are also required to develop a monitoring plan which any hired contractor or plant personnel must follow.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 17

Comment: We recommend that the initial survey for new well sites be conducted within 30 days of the end of the first well completion or upon the date the site begins production, whichever is later. For modified well sites, we recommend the initial survey would be required to be conducted within 30 days of the site modification. We've observed that generally at the end of the first well completion or when the site begins production, that the operator does have workers regularly onsite practically daily, most likely to monitor operations and ensure that all equipment is working properly. Thus it is no burden to be sufficiently ready to have an initial survey conducted within in 30 days of well completion, production or modification. We recommend that this provision stand as written and that no revision be made to lengthen the time period beyond 30 days.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 42

Comment: We recommend the proposed standards that require operators begin monitoring fugitive emissions components at a well site within 30 days of the initial startup of the first well completion for a new well or within 30 days of well site modification. 30 days provides sufficient time to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Roy Rusty Bennett
Commenter Affiliation: Mehoopany Creek Watershed
Document Control Number: EPA-HQ-OAR-2010-0505-6816
Comment Excerpt Number: 8

Comment: In order to sufficiently monitor compliance, we recommend that initial surveys be done within 30 days at all well sites and compressor stations.

We recommend the proposed standards that require operators begin monitoring fugitive emissions components at a well site within 30 days of the initial startup of the first well completion for a new well or within 30 days of well site modification.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: J. Roger Kelley
Commenter Affiliation: Domestic Energy Producer's Alliance (DEPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6793
Comment Excerpt Number: 13

Comment: Finally, after the rule goes into effect, the going-forward requirement to conduct a survey of fugitive emissions within 30 days is incompatible with typical industry practices. At 30 days after the first well completion or modification, operators are typically still evaluating the well, and it is not feasible or practicable to conduct an initial survey of fugitive emissions at that point. Operators typically need more than 30 days to even evaluate the well and understand all the equipment that will be on site. DEPA therefore requests that EPA allow more time before initial monitoring of fugitive emissions is required. DEPA proposes that the initial survey be required within 90 days of well completion. Synchronizing these requirements would allow operators to combine the fugitive emissions survey with the site registration field visit, which operators often perform as part of their best practices.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 28, 44

Comment: If EPA fails to recognize the negative impact of the proposed rule and continues to finalize the rule, the PBPA requests that the 30-day time limit to begin LDAR surveys on affected facilities be extended to 90 days. More time is needed by operators to finalize battery construction and engineering design as initial production is gauged, quantitated and qualitied. The addition or removal of equipment require both internal planning, scheduling of contracted work crews, and frequently the ordering of additional parts or equipment. Additionally the third party contractors performing the LDAR must be given time to schedule visits, schedule air travel, reserve hotel stays and schedule the rental of all-wheel-drive vehicles.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Shawn Bennett, Executive Vice President
Commenter Affiliation: Ohio Oil & Gas Association (OOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6921
Comment Excerpt Number: 12

Comment: Absent an exemption as requested in the General Comments above, the proposed rule requires that initial monitoring be performed within 30 days of the first well completion. This requirement is inconsistent with Ohio's General Permit ("GP") for well pads which requires the initial monitoring within 90 days of startup. Moreover, it would be very difficult to complete initial monitoring within 30 days because there could be several additional well completions within the 30-day period, making an initial survey impossible because of the presence of temporary equipment at the well site. Thus, the Association believes that the proposed rule should be revised to the 90-day period consistent with Ohio's GP program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 9

Comment: The Proposed OOOOa Rule requires that the fugitive emissions survey be completed within 30 days of the first well completion for each collection of fugitive components at a new well site or upon the date the well site begins the production phase for other wells. This timing may not make sense depending on the equipment on-site and used for well completions versus normal production. All of the production equipment may not be installed or operational when the well site begins the production phase for the first well at the site (as described in the Proposed OOOOa Rule). Additionally, within the first 30 days, production at new well sites is evaluated and is not generally representative of ongoing production. To address this issue, Hess proposes that the initial survey be required within 90 days of well completion. This schedule is consistent with the well registration schedule in North Dakota, which requires that operators file a well registration within 90 days of well completion. Synchronizing these requirements would allow operators to combine the fugitive emissions survey with the site registration field visit, which operators often perform as part of their best practices.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 13

Comment: Timing of initial survey is too stringent

Dictating a particular technology (OGI) and then requiring the initial survey be conducted within 30 days is an unreasonably arbitrarily and capriciously tight time period. Even though Pioneer owns a number of IR cameras, Pioneer's operations throughout Texas and Colorado are geographically dispersed such that it may not be realistic to get the OGI device from one new or modified location to another within the prescribed timeframe, especially once industry rebounds from the current downturn and drilling activity ramps up. Additionally, with multi-well pad drilling comes successive start of production dates at a single battery. An approach that would be preferable to Pioneer is to allow an operator to wait and survey once all planned wells have been drilled and brought into a tank battery, but not to exceed a certain timeframe such as 90 days. In other words, the date of last production would be the date the last planned well at a facility was put into production. The practice in Colorado allows this flexibility in regard to the initial LDAR survey at a facility. Otherwise, an operator may be repeatedly going out to conduct an initial survey on the same facility as each new consecutive well is brought on-line, which would be an inefficient and burdensome exercise with minimal to no value to the environment.

Also, another point to consider as TXOGA explains, is that under 2012 Subpart OOOO, storage tanks do not need to be assessed until 30 days after start-up and a control device does not need to be installed until another 30 days (i.e. 60 days total after start-up). Therefore, the closed-vent system, including the piping, valves, flanges and other fugitive components, may not be installed until at least 60 days after a new well is tied into production at an existing or new facility. Additional time should then be allowed for production to regulate and to ensure all equipment is functioning as it should.

Therefore, for the reasons stated above, Pioneer requests that a more reasonable time be designated, such as at least 90 days in order to conduct an initial survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 10

Comment: EPA Must Afford Operators More Time to Conduct Initial Surveys under NSPS OOOOa

EPA solicits comment on whether thirty days is an appropriate amount of time to begin conducting fugitive emissions monitoring on new and modified well sites. 80 Fed. Reg. at 56638-56639. EPA further provides that the thirty days will allow operators to secure qualified contractors and equipment necessary for the initial monitoring survey. While the availability of contractors and equipment are important considerations for when an initial fugitive emissions survey is appropriate, EPA fails to recognize other important realities of bringing new and modified oil and natural gas wells online. First, as EPA appreciates from the difficulty in accurately defining "flowback" in previous iterations of NSPS OOOO, the exact duration of completion activities and the transition from completion to production at well sites is difficult to predict and define. Temporary reduced emissions completion equipment, including sand traps, separators and storage vessels, may still be on site and the final production design may not yet be in place thirty days after the "initial startup of the first well completion." Second, operators risk harming a well's long term productivity if it must be shut in for repairs during the first thirty days of production. Such a practice would compromise operators' efforts to responsibly develop oil and natural gas resources.

QEP requests that EPA acknowledge this unpredictable, yet essential, transitional time period for oil and gas well sites in the fugitive emission control program by providing operators with sixty days to conduct an initial fugitive emissions survey for new and modified well sites in 40 CFR §60.5397a(f)(1). EPA will receive more accurate fugitive emission data if operators are allotted more time to finalize and confirm production site design.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Stuart Spencer, Associate Director, Office of Air Quality
Commenter Affiliation: Arkansas Department of Environmental Quality (ADEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6924
Comment Excerpt Number: 3

Comment: Dictating a particular technology (OGI/FLIR) and then requiring the initial survey be conducted within 30 days (and repaired within 15 days) is an unreasonably tight time period-especially for smaller entities and operations with disperse and remote locations. These timeframes should be extended to 60 and 30 days respectively. Smaller entities and some independent operators that cannot afford the dictated technology are then at the mercy of the market to comply within 30 days. Especially during the early implementation of the new rules, many sources are likely to incur enforcement/liability through no fault of their own due to an inability to purchase the technology or hire service providers with the necessary capabilities.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 17

Comment: Under the proposed rules (60.5397a (f)(1)), EPA requires the initial monitoring survey to be conducted within 30 days of "first well completion" or site "modification". Well completion is not defined under the proposed rule. So it's not clear if the 30-days is based on when the well completion first begins or when the well completion ends (with completions lasting for several days). However, SWN believes the intent is to have the initial fugitive emissions survey conducted within 30-days of when the well completion process is completed and gas is flowing to the sales line or oil is being collected for sales.

Additionally, SWN comments that there are cases where completion flowback activities are conducted on a well and the well may initially flow to the sales line or storage tank. However, due to several variables (including economics), the well may be shut-in after this initial completion flowback. During that time the well and ancillary equipment (that could result in potential fugitive emissions) are no longer under pressure or operating and fugitive emissions associated with the well and equipment not present. Therefore the rule should be revised to address this operating practice.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 11

Comment: Timing for new sources: 30 days to survey each new and modified site will result in inefficient travel patterns. For example, on a multi-well pad, if 30 days pass between the completion of the first and last wells, the surveyor will have to revisit the same well pad twice for initial inspections. The provision to require four months to pass between inspections could result in this double survey issue persisting for the life of the wellsite. We recommend the initial review period be 180 days from the start of production to provide opportunities to reduce travel time by grouping several initial inspections. Additionally, we request greater flexibility on the time between inspections by eliminating the provision requiring four months to pass between surveys.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 11

Comment: EPA proposed in 40 CPR §60.5397a(f)(1) that the initial monitoring survey on fugitive emissions components be conducted within 30 days of the first well completion date at a new well site or upon the date the well site begins the production phase for other wells. The proposed requirement to conduct the initial survey within 30 days of the first well completion is not practicable and may result in incomplete information being gathered for purposes of compliance.

Specifically, Anadarko sometimes completes a well flowback then shuts the well in for a period of time before startup of production. Production startup may not be scheduled far enough in advance to allow enough time to mobilize a survey crew. Additionally, a facility may be started up in phases if the facility is not fully operational until a period of time after startup of production. Until a production facility is fully operational, a monitoring survey will not capture all potential sources of fugitive emissions.

Solution: Assuming that EPA wants the survey conducted in a manner to collect all of the relevant data, Anadarko proposes that the first survey be required 90 days after "startup of production." This will provide adequate time to schedule and mobilize a monitoring survey of a fully operational facility.

The following is proposed regulatory text to address the concerns raised above (proposed edits are underlined):

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: J. Roger Kelley, Director, Regulatory Affairs
Commenter Affiliation: Continental Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6963
Comment Excerpt Number: 14

Comment: Add Flexibility to the Requirement of an Initial LDAR Inspection.

Requiring operators to perform initial LDAR inspections within 30 days of a well's first production is overly burdensome and not cost effective. This is true for both smaller and larger operators, but especially so for smaller operators and those with facilities in numerous, geographically dispersed plays throughout the U.S. Left unchanged, this provision would require operators to pay for LDAR mobilization and inspection events during every month of the year.

EPA should relax the requirement so that the initial inspection is required to be performed within the first 6 months of production. Operators are already actively training their production personnel to identify and repair leaks, which should result in their having few, if any, facilities that exceed the consecutive 3% (of components) leak rate trigger for quarterly inspections; therefore, a requirement to perform the initial inspection within the first 6 months of production would recognize the leak detection and repair benefits already being derived from routine inspections and impose a far more reasonable and achievable LDAR requirement.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Jack Dalrymple, Chairman, Governor, Wayne Stenehjem, Attorney General and Doug Goehring, Agriculture Commissioner
Commenter Affiliation: North Dakota Industrial Commission (NDIC)

Document Control Number: EPA-HQ-OAR-2010-0505-6977
Comment Excerpt Number: 4

Comment: Compliance required within 60 days of publication of the final rule in the Federal Register and the first survey of equipment required within 30 days of well completion: The time frame is too short. The well completions covered in the proposed rule are spread over thousands of square miles and weather conditions in North Dakota can be very severe and dangerous for extended periods of time.

Response: We acknowledge that at certain temperatures, an OGI instrument may not operate properly or at all. Therefore, in the final rule we have incorporated a waiver for owners or operators that have compressor stations in areas of the country that have an average monthly temperatures below 0°F (based on historic climate data). If two of three months of a quarterly monitoring period each have an average temperature below 0°F, fugitive emissions monitoring is waived for that quarter. See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Clement J. Frost, Chairman
Commenter Affiliation: Southern Ute Indian Tribe Council
Document Control Number: EPA-HQ-OAR-2010-0505-6446
Comment Excerpt Number: 4

Comment: The Tribe recommends that the initial leak survey be conducted within 60 days of initial startup. EPA is proposing that the initial leak survey be conducted within 30 days from the startup of a new compressor station. Due to the complexities involved in starting up a new compressor and the potential delays and issues that are likely to be encountered, the Tribe recommends that the initial leak survey be conducted within 60 days of initial startup. This will allow an appropriate window of time for issues to be addressed before the survey is to take place.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 23

Comment: Further, we recommend facilities to locate sources of fugitive emissions and to repair those sources. For new compressor stations, the initial survey would have to be conducted within 30 days of site startup. For modified compressor stations, the initial survey would be required within 30 days of the site modification. After the initial survey, surveys would be required semiannually.

We've observed that generally, that operators do have workers regularly onsite practically daily, most likely to monitor operations and ensure that all equipment is working properly. When a compressor station is newly place in operation, workers and contractors are regularly onsite monitoring and fine tuning the operation. Thus it is no burden to be sufficiently ready to have an initial survey conducted within in 30 days of startup. We recommend that this provision stand as written and that no revision be made to lengthen the time period beyond 30 days.

We recommend the proposed standards would require that operators begin monitoring fugitive emissions components at compressor stations with 30 days of the initial startup of a new compressor station or within 30 days of a modification of a compressor station. 30 days provides sufficient time to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Roy Rusty Bennett
Commenter Affiliation: Mehoopany Creek Watershed
Document Control Number: EPA-HQ-OAR-2010-0505-6816
Comment Excerpt Number: 9

Comment: In order to sufficiently monitor compliance, we recommend that initial surveys be done within 30 days at all well sites and compressor stations.

Additionally, we recommend the initial survey for all compressor stations be completed within 30 days of start-up.

We recommend the proposed standards would require that operators begin monitoring fugitive emissions components at compressor stations with 30 days of the initial startup of a new compressor station or within 30 days of a modification of a compressor station.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 23

Comment: EPA should extend the time period for the initial survey from 30 to 180 days after a startup or modification

Under the proposed NSPS, operators must conduct an initial fugitive emission survey within 30 days of site startup or modification. EPA has asked for comment on whether 30 days is an appropriate period. Enterprise does not believe that 30 days is enough time to conduct the initial monitoring survey. Because natural gas pipelines are highly regulated, the period immediately following startup is an incredibly busy time for compliance personnel at these companies. First, a natural gas gathering line/system must be permitted, installed and operational in the area. Compressor stations collecting field gas may then require several months after initial startup to complete all the necessary well ties into the station. Many of these initial tasks have important safety and operational considerations, and require the full attention of the operator's personnel. Given these competing considerations, it is not feasible to also complete an initial fugitive emission survey within this time. Enterprise proposes that instead, the final rule should allow operators 180 days from the time of the site startup or modification to complete this survey. This will allow operators sufficient time to perform surveys after other safety and regulatory concerns related to startup or a modification have been addressed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 25

Comment: The Initial Survey Schedule Should Be Revised to Allow 180 days from Startup, which Is Consistent with Performance Test Schedules in Other NSPS that Affect Compressor Stations.

The Proposed Rule requires an initial survey within 30 days of startup, and EPA requests comment on that requirement. Startup of a facility generally encompasses a busy period for operators, and includes schedules for other regulatory requirements associated with facility operations. More consistency with other NSPS and a more reasonable schedule is warranted. For example, most new compressor stations include natural gas-fired compressor drivers – i.e., reciprocating engines or combustion turbines. These units are also subject to NSPS and NESHAP regulations, such as Part 60, Subpart JJJJ and Part 63, Subpart ZZZZ for reciprocating engines, and Part 60, Subpart KKKK for turbines. Those regulations allow a longer period to complete initial performance tests, and similar schedules are warranted for Subpart OOOOa. Similar schedules will also simplify managing compliance during the busy period following initial startup. Subpart JJJJ, Subpart KKKK, and Subpart ZZZZ allow 180 days or longer to complete the initial performance test. A similar schedule is warranted to complete the initial leak monitoring survey. INGAA recommends revising the schedule for the initial survey to within 180 days of startup.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 11

Comment: In addition, EPA's proposal would require an initial survey within 30 days of startup. AGA suggests that the initial survey be required within 180 days of startup. A 180-day schedule would be consistent with the schedule for the initial performance test required for a different NSPS that may also apply to a compressor station – i.e., Subpart JJJJ for spark-ignited engines. In addition, allowing 180 days from startup will assist operators in managing compliance schedules during the busy period following initial startup.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 15

Comment: EPA proposes a complex and aggressive monitoring program with deadlines that are not only too strict, but that vary depending on the number of leaks detected during prior surveys. This program would add significant and unnecessary cost and complexity for operators who operate numerous compressor stations in remote locations. Thus, in order to realize the goals of the NSPS program in a way that reflects the pragmatic realities of the industry, GPA urges EPA to extend the deadline for initial surveys and to provide a uniform annual monitoring requirement for subsequent surveys.

At the outset, GPA urges EPA to extend the deadline for initial surveys to a minimum of 180 days. EPA's current proposal requires operates to "conduct an initial monitoring survey within 30 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station. For modified compressor stations, the initial monitoring survey of the collection of fugitive emissions components must be conducted within 30 days of the modification" Proposed 40 C.F.R. § 60.5397a(f)(2). The first 30 days after starting a new compressor station or adding compression to an existing compressor station is a particularly frenetic time where temporary construction staff, including their heavy equipment, are on-site. Introducing more internal or external staff during this time to count components and perform a monitoring survey would increase the risk for a safety incident. It is also common on new construction projects that not all equipment would be installed and started up when the first compressor begins operation. For example, a compressor station with multiple compressors, might initially startup with only one compressor in service. Therefore, it would be likely that not all components will be available to count or survey within the first 30 days after operations begin. Further complicating the short deadline, compressor stations are often remote, unmanned sites that will require significant coordination by contractors and operators to conduct monitoring surveys and perform necessary repairs. Access to these sites is often restricted depending on the time of the year. For example, sites located in northern and mountainous regions often experience significant snowfall and extreme temperatures that prevents access for long periods of time. Likewise, site access can be limited in coastal areas due to hurricanes and flooding. Additional access restrictions occur from lease agreements with landowners that may require coordination for gates that must be manually opened and closed or exclude access during hunting seasons. In addition, endangered species agreements may limit the time when access may be permitted for monitoring surveys. Expanding the initial survey deadline to 180 days will give operators more flexibility to coordinate with contractors and to address weather-related concerns and, most importantly, reduce the risk of a safety incident.

Also, such a deadline is consistent with existing 180-day initial compliance deadlines under NSPS Subpart OOOO, which EPA acknowledged as appropriate in this rulemaking. See 80 Fed. Reg. at 56647-48; see also 40 C.F.R. 60.482-1a(a) (allowing a 180 initial compliance period for gas processing plants). Furthermore, EPA also includes a 180-day initial startup deadline for fugitive emissions monitoring for the synthetic organic chemicals manufacturing industry ("SOCMI") under Subparts VV and VVa. 40 C.F.R. §§ 60.482-1(a), 60.852-1a(a). Both of these rules regulate industrial facilities that typically have on-site maintenance staff. EPA offers no explanation of why a shorter initial compliance deadline is appropriate for the oil and natural gas production and gas gathering sectors that are typically remote and unmanned sites. Providing these sectors with the same 180-day deadline will allow operators to develop monitoring plans, schedule contractors, and prepare for any maintenance issues.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4 for discussion regarding the initial monitoring survey. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9 for discussion regarding compressor station monitoring frequency.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 20

Comment: Under EPA's proposal, owners and operators would have to conduct an initial survey of the collection of fugitive emissions components within 30 days of site startup or site modification. In addition, EPA proposes that owners or operators of compressor stations repair the sources of fugitive emissions within 15 days after they are found.

These time periods are insufficient. Once again, compressor stations are very numerous and often remotely located and unmanned; also, as previously noted, OGI personnel and equipment may be limited. In addition, some repairs might be delayed due to safety issues, unavailability of parts or maintenance personnel, weather conditions, or similar issues. When these factors are taken into account, it becomes clear that the proposed survey and repair deadlines are unrealistically short. We urge EPA to allow 180 days after startup or modification to come into compliance; in this regard we note that in Subparts VV, VVa, and KKK, EPA provides owners and operators of affected facilities 180 days after initial startup to come into compliance, and we see no reason why the time period should be significantly shorter for compressor stations. We also urge EPA to extend the other applicable deadlines, so as to provide a 30-day period for initial surveys; an additional 30 days for repairs; and an additional 30 days for resurveys. Our suggested changes would ease the burden on owners and operators and would properly account for the real-world characteristics, and great number of, compressor stations in the oil and gas industry.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 10

Comment: In addition, EPA's proposal would require an initial survey within 30 days of startup. AGA suggests that the initial survey be required within 180 days of startup. A 180-day schedule would be consistent with the schedule for the initial performance test required for a different NSPS that may also apply to a compressor station – i.e., Subpart JJJJ for spark-ignited engines. In addition, allowing 180 days from startup will assist operators in managing compliance schedules during the busy period following initial startup.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 5

Comment: WBI Energy recommends that the first survey be completed within the same timeframes specified in 40 CFR §60.8(a). A newly constructed compressor station may have many NSPS affected sources requiring performance tests and initial compliance monitoring. Upon completion of construction at a compressor station it tends to take some amount of time to get the facility functioning at its maximum capacity. Consistency with other similar monitoring requirements would allow the affected company to better coordinate initial monitoring requirements as opposed to tracking several requirements having a variety of due dates.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

4.7 Applicability

Commenter Name: Russell V. Randle, Counsel, Squire Patton Boggs (US) LLP on behalf of Atlas Copco North America, LLC
Commenter Affiliation: Atlas Copco North America, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5533
Comment Excerpt Number: 3

Comment: As an example of the issues on which Atlas is considering comment, the maintenance of such equipment will occasionally require the venting of gasses from within the equipment. Equipment which would ordinarily meet EPA's standards may not do so for short periods when such venting is required, as it may be at times for safety reasons. It will be important to address these maintenance and emergency venting situations in the final rule, both to provide clarity about what is permissible, and in order to assure safe and compliant operations. Recent case law raises questions as to whether such issues can be addressed in local permits if these issues are not addressed in the underlying rule.

Response: The definition of fugitive emissions component has been revised to exclude devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps. Venting from an activated pressure relief device would not be fugitive emissions, however, if the pressure relief device is not activated then any emissions from the device would be fugitive emissions.

Commenter Name: Douglas E. Jones, Chairman
Commenter Affiliation: Pennsylvania Grade Crude Oil Coalition (PGCC)
Document Control Number: EPA-HQ-OAR-2010-0505-6239
Comment Excerpt Number: 5

Comment: With respect to fugitive emissions, the conventional industry in Pennsylvania is composed largely of stripper wells in under pressured reservoirs. These wells decline quickly, as much as 70% to 80% year over year when completed. As a result wells have relatively low well head pressures to begin with and much lower pressures than that very quickly. Within the first year of operations a high percentage of wells will be below 100 psig operating pressures. Testing for fugitive emissions would be prohibitively expensive and unproductive.

The PGCC requests an exemption from fugitive emissions testing and reporting for stripper wells, low pressure wells and conventional wells.

Response: The information received during the comment period for the proposed rule shows that these low production well sites have the same type of equipment (e.g., separators, storage vessels) and components (e.g., valves, flanges) as production well sites with production greater than 15 boe per day. This indicates that the fugitive emissions from low production well sites are similar to that of conventional well sites. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from conventional production well sites. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and conventional production well sites are comparable. We have included the exemption for sites that only contains one or more wellheads. See section VI.F.1.b of the preamble for further discussion regarding low production wells.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 24

Comment: CONSOL also believes that "low pressure wells" should be excluded from the fugitive emission requirements of proposed Subpart OOOOa.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6239, Excerpt 5.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 109

Comment: Only Sites With Major Equipment (Such As Separator, Heater, or Glycol Dehydrator) Should Be Subject. The Proposed Requirement To Exempt Sites With Only Wellheads Is Not Adequate

§60.5365a(i)(2) exempts well sites that only contain one or more wellheads. "*(2) A well site that only contains one or more wellheads is not an affected facility under this subpart.*" API agrees that a well site consisting only of wellheads should be exempt due to the small number of fugitive components. It would be overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site.

Similarly, API believes that additional exemptions should apply. EPA's Model Plants used in the TSD are based on the following assumed equipment and component counts. [Table 27-1 EPA Model Well Site Equipment and Component Counts, from TSD]

EPA uses these model well sites to establish the cost effective basis for the rule. Implementing LDAR is not cost effective at sites with component counts less than the model well sites. As discussed in Section 27.3.8, LDAR is not cost effective using the lower, unrounded estimates of component counts for the model well sites even without considering costs that EPA omitted from the cost effectiveness analyses. In addition, it is overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site. API believes that any well site with equipment configurations or component counts less than the model well sites should be exempt from the LDAR requirements. This would exclude well sites with just wellheads, meter runs, pipeline risers, etc. and no production equipment, such as separators, heaters, and dehydrators.

Response: We agree with the commenter with regard to the exclusion of well site that only contains one or more wellheads and have included this exemption in the final rule. However, we disagree with an exemption for any well site with equipment configurations or component counts less than the model well sites. Data received during the comment period for the proposed rule shows that the potential emissions from these well sites could be as significant as the emissions from conventional production well sites.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 114

Comment: Components at Enhanced Oil Recovery Fields Must Be Exempted from the Fugitive Emissions Standards in Subpart OOOOa

Following are the conclusions regarding EOR.

- EOR fields are very different from the types of operations EPA evaluated in the development of the proposed NSPS Subpart OOOOa requirements.
- The gas streams at EOR fields have an inert gas content radically higher than the representative gas composition used by EPA in the evaluation of control options for subpart OOOOa.
- These differences will have a significant impact on the VOC and methane baseline emissions, emission reductions, and cost effectiveness.
- Based on the fact that EPA did not once mention EOR in the preamble or background documents, it is clear that there was no evaluation conducted for this segment of the oil and natural gas industry.

Given these facts, EPA must include an exemption for EOR operations from the fugitive leak requirements in NSPS subpart OOOOa. Recommended regulatory changes are provided in Section 27.2.12.

If EPA elects not to incorporate the changes suggested by API above, EPA cannot require EOR fields to comply with the fugitive leak requirements in NSPS subpart OOOOa without a full evaluation of emissions, controls, costs, and impacts specific to these unique operations in the oil and natural gas industry and a separate proposal that provides the rationale for any rulemaking for EOR operations. If EPA chooses to follow the path, API will work with EPA to gather accurate information for their analysis.

Response: We disagree with the commenter. The collection of fugitive emissions components at all well sites, including enhanced oil recovery fields, are affected facilities and must meet the requirements of the fugitive emissions monitoring and repair program.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 9

Comment: Antero supports the exclusion of well sites where only one or more wellheads are present as proposed in 40 CFR § 60.5397a. Antero also suggests that ancillary equipment also be excluded.

Antero proposes that ancillary equipment associated with dry gas well sites be excluded from the definition of an "affected facility." USEPA defines an "affected facility" as a collection of fugitive emission components at a well site. The leasehold positions for many operators in the Marcellus and Utica gas shale plays include areas with dry gas. USEPA is contemplating an exclusion for dry gas well sites that "...consists only of one or more wellheads, or "Christmas Trees," and have no ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators and pneumatic controllers. Antero's dry gas well pads are exempt from state regulation and the ancillary equipment consists of produced water tanks (no oil), separators and pneumatic controllers but they do not include compressors, vapor recovery units or combustors to flare flash emissions generated by oil production. Antero proposes that the USEPA exclusion from fugitive emission requirements for "Christmas Trees" be expanded to include ancillary equipment at dry gas well pads as described above.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 109.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 8

Comment: PIOGA also believes that “low pressure wells” should be excluded from the fugitive emission requirements of proposed Subpart OOOOa.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6239, Excerpt 5.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 28

Comment: PIOGA supports the exclusion of well sites that contain only wellheads from Subpart OOOOa.

While PIOGA supports the exclusion of well sites that contain only wellheads, the exclusion is too narrow. PIOGA suggests expanding the exclusion to well sites that include basic equipment (e.g., measurement equipment, heater, pneumatic controllers, and tank) or defining a threshold based on the number of fugitive emission components at a well site. Well sites with fugitive component counts of less than the threshold would be excluded from the proposed Subpart OOOOa fugitive emission requirements. Even in dry gas areas, provisions must be made to account for collection of trace quantities of produced water. Such provisions could include a condensate (i.e., produced water) collection system, pneumatic controller(s), heater, and a produced water tank.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 109.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 37

Comment: EPA's Proposed Christmas Tree / Single Well Exemption

EPA also proposes to exclude from LDAR well sites that contain "one or more wellheads" and no associated equipment. 80 Fed. Reg. at 56,612. EPA justifies this exclusion with its belief that such well sites have low emissions due to the low number of components existing on wellheads that are not associated with production equipment. *Id*. at 56,611.

If EPA retains the wellhead exemption, it should narrow it to apply to single wellheads only. Well sites that contain more than one wellhead must not be exempt, since there is no limit to the number of components (and therefore sources of fugitive emissions) that could exist at such sites, even if no associated equipment is present. Even without the addition of associated equipment, a well site with multiple single wellheads could be a significant source of emissions, in particular if there is a very large leak coming from one of the wellheads. If the agency retains this exemption, it must therefore narrow it to sites with just one wellhead.

Furthermore, if EPA retains the wellhead exemption, the agency must ensure that it is structured in a way that prevents operators from separating wellheads from ancillary equipment, such as separators and dehydrators, in order to exempt *all* of the equipment from fugitive standards.

Operators could conceivably locate separators and dehydrators at separate locations from wellheads. If no tanks or compressors were present at these sites, operators may interpret the standards, as proposed, as exempting the separators and dehydrators, in addition to the wellheads. If EPA retains this exemption, the Agency must add language to the standards explicitly applying the fugitive standards to any separators, heaters, dehydrators, etc., associated with the well, even if located at a site with no wellheads or tanks.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 109.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 79

Comment: Second, under the proposed updates to the New Source Performance Standards for methane and VOCs, EPA has categorically exempted a number of types of facilities. Like the egg slicer permitting, this draws an artificial line that ignores the impact the facilities or groups of facilities. For example, EPA proposes to exempt compressors located at well sites from all requirements under the new rule because they are "typically small and low-emitting." EPA has proposed to exempt low-production well sites and well sites with only wellheads from the leak detection and repair requirements. Rather than exempting facilities by type, EPA should set an emissions threshold. This would have the same effect of excluding low-emitting facilities from the rule without mistakenly cutting out the big emitters.

EPA established an emissions threshold for the storage tanks under the 2012 NSPS rule, and it is capable of doing so again. We would urge this change.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6239, Excerpt 5 and DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 109.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 107

Comment: The Definition Of Well Site In §60.5430a Is Problematic And A New Definition For "Central Production Site" Is Needed

The proposed definition of "well site" includes both a well pad and other sites with process equipment that receives produced fluids from wells. The definition is problematic in that it can be interpreted to mean that all well pads connected to a tank battery or other centralized station can be aggregated as part of a single well site. This is unprecedented and appears to be an attempt to aggregate sites that are not otherwise contiguous or adjacent but instead functionally interrelated. This could lead to conflict with the Source Determination rule leading to potential permitting questions subject to variable interpretations. In Source Determination, courts have ruled against functional interrelatedness. In effect, EPA is applying Option 2 from the Source Determination proposal to define a source in NSPS. **It is inappropriate to aggregate sites.**

This erroneous definition change is being made to support the misconception that hydraulic fracturing increases fugitive emissions and constitutes a modification. The modification issue is discussed in more detail below in Section 0. The practical result of this error is that EPA's proposed definition of "well site" dissociates from the common sense and generally accepted and practically understood use of the term within industry. As well, tank batteries may or may not be tank batteries because of a false regulatory construct based on the activity at a distinctly separate surface site that has one or more wells. Additionally, the wellhead only exemption in paragraph (2) is rendered meaningless since aggregating separate surface sites into one means there will be no wellhead only well sites since wellhead only sites can produce to centralized tank batteries which would now be considered part of the wellhead only well site. EPA should instead consider a well site to be a distinct and separate surface site from a central processing site with no wellheads. The proposed definition change needs to be scrapped and either make no change to the original definition in Subpart OOOO or alternatively modify the definition as API recommends below in Section 27.2.12.

Another outfall of trying to define a well site other than in its generally accepted and common sense definition is that EPA assumes that any wellsite such as a wellhead only site produces to a central tank battery. This is not always true, there are other possibilities. A well could produce to a tank battery, a compressor station, or a tank battery combined with a compressor station, any of which may also happen to have one or more wells on the same surface site, making them well sites. Consequently, the collection of well sites that go to a central tank battery with no wells make the battery and the collection of well sites an aggregated single well site. But, if the central tank battery happens to include an onsite well, it is a separate well site, not an aggregated well site. These various operating scenarios complicate determinations of well site as proposed when a definition includes sites with no wells. This argues for each separate surface site to be evaluated independently for modifications without attempted aggregation.

As described in the previous paragraph, there are multiple centralized site configurations which complicate the applicability requirements in paragraphs §60.5365a(i) and (j). While the previous paragraphs discussed the issues with the definition of a "well site", a new definition is needed to more accurately account for centralized sites. For paragraph (j) API recommends the term "central production site" and "transmission compressor station" replace the use of the single term "compressor station". A central production site properly defined encompasses central gathering and boosting compressor stations, tank batteries, and combination tank batteries and compressor stations that have no wellheads located on the same surface site. Central production sites are located between a well site and natural gas processing plant or transmission pipeline. The recommended definition is found below at the end of in Section 27.2.12.

Response: We disagree with the commenter that the definition of "well site" should not include tank batteries located away from the well site. We do not believe that the distance the tank battery is located from the well site is a determining factor for whether fugitive emissions monitoring should be required for storage vessels. If the storage vessels are "collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries)" as stated in the definition of "well site," then they are subject to applicable requirements just as would those storage vessels in the immediate vicinity of the well site. Additionally, we believe that excluding tank batteries not located at the well site could incentivize some owners or operators to place new tank batteries further away from well sites to make use of such an exemption. Also see section VI.F.1.j of the preamble to the rule for further discussion.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 10

Comment: EPA should revise its definition of "well site" to include only those facilities owned or operated directly by the producer. Any other definition would create significant implementation and compliance concerns.

Response: The collection of fugitive emission components at a well site, regardless of the owner or operator, is the affected facility and is subject to the fugitive emissions monitoring and repair program requirements specified in §60.5397a, including . The introductory text of §60.5365a states that "[y]ou are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification or reconstruction after September 18, 2015." Therefore the owner or operator is responsible for complying with the applicable standards. The commenter should be mindful, however, of the definition of "owner or operator" in §60.2 of the General Provisions which states that owner or operator means "any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part." We believe that the resolution for any leaking components identified during surveys can be managed by the operator through cooperative agreements with other potential owners at the site.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 31

Comment: The proposed definition of "well site" includes tank batteries (including central tank batteries) and injection wells. Section 60.5365a(i)(2) exempts wellhead-only sites from OOOOa fugitive emissions requirements, stating "[a] well site that only contains one or more wellheads is not an affected facility under this subpart." To clarify this exemption and avoid possible confusion, the Alliance recommends revision to include italics in § 60.5430a as follows:

> *Well site* means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at § 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries)*, and excludes wellhead-only well sites*.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 107.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 18

Comment: §60.5397a(a) - Definition of Fugitive Emission

- WBI Energy recommends changing the definition of fugitive emissions in the proposed rule so that alternative monitoring techniques to OGI can be used for monitoring these emissions. WBI Energy suggests using the established definition for fugitive emissions found in the Title V and New Source Review regulations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2.

Commenter Name: Laura K. Perry, Coordinator - Air Quality
Commenter Affiliation: ConocoPhillips Alaska, Inc. (CPAI)
Document Control Number: EPA-HQ-OAR-2010-0505-6947
Comment Excerpt Number: 5

Comment: The well site exemption for fugitive emissions found in §60.5365a(i)(2) states:

> "*A well site that only contains one or more wellheads is not an affected facility*"

In the proposed rule preamble at 80 FR 56611, EPA states this definition is meant to exclude from LDAR requirements "well sites that contain only wellheads." We are not certain any such producing well site exists on the Alaskan North Slope. Rather, because of the remote nature of our operations, the need to freeze protect, and the number of wells we may have on a pad, there is nearly always more than just wellheads at a well site. But, with few exceptions, there is also no processing or production fluid storage that takes place at a well site. EPA makes clear on the same page of the preamble that they want to include in the LDAR requirements those well sites that contain "ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators, and pneumatic controllers." In ConocoPhillips' Alaska North Slope operations, there is only one such site. The rest of our drill sites contain, along with the wellheads, mainly electrical modules, manifold buildings, line heaters, and small methanol tanks for freeze protection.

It appears EPA, in the §60.5365a(i)(2) exclusion, wants to ensure no well sites that engage in any processing or storage of production fluids enjoy the exemption. If our understanding of this is correct, we suggest the exclusion language would be much more clear if worded as follows:

[Note: Underlined language below indicates the commenters' suggested language additions.]

> *"A well site that only contains one or more wellheads or that does not process (i.e. separate) or store any sales quality produced fluids is not an affected facility."*

Response: The exemption is intended to include only well sites that contain only one or more well heads without any ancillary equipment.

Commenter Name: Laura K. Perry, Coordinator - Air Quality
Commenter Affiliation: ConocoPhillips Alaska, Inc. (CPAI)
Document Control Number: EPA-HQ-OAR-2010-0505-6947
Comment Excerpt Number: 7

Comment: The definition of "well site" is confusing as it could be read to include production facility pads that contain no producing wells. We do not believe EPA intends this outcome but the matter could be clarified by including in the definition language that explicitly states production pads that contain no producing wells are not considered well sites.

Response: We did not intend to include production well sites that contain no producing wells in the definition of "well site".

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 117

Comment: To adequately address the problem of methane leakage, all production stages where methane leaks should be covered.

Response: The final rule includes requirements for all stages of production with the exception of well sites that only contain one or more wellheads.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 6

Comment: The proposed rule penalizes centralized tank batteries that would be modified every time a well or piping is added to the battery. Tank batteries that would be built for 30+ wells that are added over a period of years could potentially be required to survey the tank battery several times per year due to modifications, plus any follow up surveys. Laredo proposes that if a new well is added at an existing tank battery and production does not exceed the historical high production level for that battery, it should not be considered a modification. As written, this section would encourage companies to build new batteries instead of modifying existing batteries. Modification of a well is defined on page 56614, column 1, under section G. 3. Modification of the Collection of Fugitive Emissions Components at Well Sites and Compressor Stations.

Response: We disagree with the commenter that the addition of a new well or piping should not constitute a modification. The addition of a new well or piping increases the potential fugitive emissions from the production site and is therefore a modification. See section VIII.G.1 of the preamble for more information.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 7

Comment: Regarding the definition of modification of a compressor station, as defined on page 56614, column 1, under section G. 3. Modification of the Collection of Fugitive Emissions Components at Well Sites and Compressor Stations, it is stated in the proposed rule that the definition of modification is the addition of a compressor to a compressor station. Prior to this it stated that a modification "occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station." The definition is inconsistent through the rule and is a demonstration of the lack of understanding of changes that occur. Laredo ask how the following situation be handled: removal of an engine for an engine with less horsepower that reduces compression capacity at the station?

Response: For the final rule, we have clarified that the installation of a compressor will only trigger the fugitive monitoring requirements if it is installed as an additional compressor or if it is a replacement that is of greater horsepower than the compressor or compressors that it is replacing. So in the example listed by the commenter the replacement of an engine with an engine with less horsepower would not be a modification. See section VI.F.2.h of the preamble to the final rule for further discussion.

Commenter Name: W. Michael Scott, General Counsel
Commenter Affiliation: Trilogy Operating, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6603
Comment Excerpt Number: 43

Comment: EPA should revise its definition of "modification" at § 60.5365a(j) as "the addition of a compressor at a compressor station that results in an increase of natural gas emissions from the compressor station."

Alternatively, EPA should define "modification" at § 60.5365a(j) as "the addition of a compressor at a compressor station or physical changes that result in an increase of natural gas emissions," and explicitly exempt any potential increases in emissions that are otherwise limited by law (such as by a federal or state permit).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6474, Excerpt 7.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 40

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 36

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number 37:

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number 37

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 38

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 74

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 10

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 12

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 10

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 10

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 11

Comment: The proposed rule's definition of "modification" for fugitive emissions surveys at well sites and compressor stations is overly broad**.**

Under the Clean Air Act, the NSPS regulatory program is intended to regulate only *new, modified, or reconstructed* facilities. It is not intended to regulate *existing* facilities. By using this expansive definition of "modification" and "fugitive emissions components," the proposed Methane NSPS undermines that important statutory distinction.

The definition of "modification" of a well site under the proposed Methane NSPS in § 60.5365a(i) is overly broad because it would unnecessarily bring many existing well sites under the Rule's requirements. Under the proposed Methane NSPS, adding a single well to a network of existing wells, or hydraulically refracturing an existing well are considered "modifications" that could trigger fugitive leak detection and repair requirements. This definition is overly broad, as these are not activities that meaningfully increase the likelihood that any other equipment at the well site will leak. Single wells are frequently added to a production facility consisting of a network of existing wells. Similarly, a well may be hydraulically fractured or refractured without making meaningful changes to the existing equipment. Because there is no meaningful change in the equipment, it is unlikely that these "modifications" would have any real impact on the likelihood that that equipment would leak. As a result, this expansive definition would require operators to perform time-consuming surveys on existing equipment at a number of sites without any evidence that the existing equipment had become more likely to leak.

In the midstream context, EPA's proposed definitions of "modification" at 60.5365a(j) is likewise overly broad because it would trigger fugitive emissions monitoring at a compressor station any time that a physical change is made that would increase the compression capacity of the station. The definition would trigger the NSPS requirements in a variety of scenarios where methane and VOC emissions were not actually increased from the station. For example, many components at older compressor stations cannot be replaced with exactly identical equipment, because the equipment is no longer available. Instead, the replacement may have slightly greater horsepower than the previous version. This is a physical change that would technically increase the "compression capacity" of the station, but would not result in additional emissions, because the station would continue to operate as before. Moreover, there is no reason to think that these changes would make the compressor station more likely to have the kind of equipment leaks that the fugitive emissions rules in the Methane NSPS are designed to prevent. As a result, this definition does not serve its intended purpose of preventing emissions from leaking equipment.

Neither definition is in keeping with how EPA has defined "modifications" in the past. Under EPA's general provisions for its air programs, "modifications" are physical changes to a facility that result in an increase in the emission rate to the atmosphere of the regulated pollutant. In other words, this definition explicitly limits "modifications" to those changes that result in greater emissions. EPA's proposed definitions of "modification" at § 60.5365a(i) and § 60.5365a(j) do not contain a similar limitation. Instead, these overly broad definitions encompass *all* changes, even those which will have no impact on, or even result in a reduction in, VOC or methane emissions. For example, in some cases when a new well is added to a well site, the operator will also add a vapor recover tower, which would reduce the overall emissions from the site. Any additions to a well site or compressor station that do not result in greater VOC or methane emissions should not trigger the requirements in these Rules.

In addition, most compressor stations already operate under air permits, which limit their levels of emissions. As a result, even an increase in "compression capacity" would not result in an increase in emissions above permitted levels. EPA has recognized that air emissions that are limited by permitting requirements should be treated differently when considering a facility's PTE. For example, in the New Source Review ("NSR") program, a major source of air emissions may be treated as a synthetic minor source if the actual emissions of the source are limited by the facility's operations to below the major source emissions threshold. EPA's definition of "modification" should take into account legal restrains on a facility's PTE, such as permit restrictions, rather than consider every change in compression capacity to be a "modification." The definition of "modification" for compressor stations is also too vague, as a number of small changes to a compressor station could inadvertently result in greater "compression capacity" without resulting in additional emissions.

Response: We disagree with the commenter regarding the modification definition for well sites. We believe the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells, which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and therefore additional fugitive emission components at the well sites. We also believe that defining "modification" to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, we are finalizing the definition of "modification" of a well site, as proposed.

For compressor stations, we agree with some aspects of the issues raised by the commenter and have made the following revisions to the modification requirements in the final rule. We agree that an increase in the compression capacity that is not due to the addition of a compressor that would result in an increase of the overall design capacity of the compressor station is not a modification. We have also clarified that the installation of a compressor will only trigger the fugitive monitoring requirements if it is installed as an additional compressor or if it is a replacement that is of greater horsepower than the compressor or compressors that it is replacing.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 31

Comment: To the extent that EPA nonetheless proceeds on the path of the proposed rule regarding the definition of "modification" at existing compressor stations, and without conceding that such an approach is supportable under applicable statutes or regulations, TXOGA believes that the term compression capacity needs to be defined in the proposal if it is to be used to establish applicability.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 40.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 42

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 39

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 40

Comment: EPA should redefine "modification" in §§ 60.5365a(i) and 60.5365a(j) to only include activities which EPA can demonstrate increase the likelihood that a site will have additional VOC or methane fugitive emissions.

Alternatively, EPA should revise its definition of "modification" at § 60.5365a(i)(3) so that the addition of a well, or fracturing or refracturing of an existing well, only triggers fugitive emission survey requirements if the new or modified well expands the capacity of the well site beyond the original facility throughput design.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 40.

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC

Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 4

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 4

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 5

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 4

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 4

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 4

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 4a

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 21a

Comment: We ask EPA to further clarify that even if a well site is modified and becomes subject to the fugitive-emissions monitoring portions of the Methane NSPS, no existing storage vessel will be required to comply with the new control requirements in the Methane NSPS, unless the existing storage vessel is itself modified or reconstructed as defined by the Methane NSPS; and to confirm that these sets of requirements have independent triggers in the Methane NSPS.

Response: The commenter is correct. Storage vessels and fugitive emissions have separate affected facility and modification definitions and therefore applicability is triggered independent for each source. We do note that the collection of the fugitive emissions components at the well site could include components a tank. To the extent that tank components are included in the collection of components, those components would be required to be monitored under the well site fugitive emissions monitoring requirements.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 29

Comment: In the proposed NSPS, EPA is proposing a special definition of "modification" that would trigger the fugitive emission requirements at compressor stations: a modification would "occur when (1) a new compressor is constructed at an existing compressor station; or (2) a physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station." Once a compressor station is "modified" as defined in the rule, the operator would be required to complete the continual LDAR repairs, monitoring, and reporting for fugitive natural gas emissions at the entire compressor station.

Historically, EPA's definition of "modification" has focused on changes that can increase emissions. Under EPA's general provisions for its air programs, "modifications" are physical changes to a facility that result in an increase in the emission rate to the atmosphere of the regulated pollutant. As a result, EPA's current definition explicitly limits "modifications" to those changes that result in greater emissions. This is a meaningful and reasonable limitation on the definition: when operators change their facilities in ways that do not impact their emissions, the operators have not created any additional risks to the environment, and there is no justification for placing additional regulatory burdens on the facility.

In contrast, EPA's proposed definition of "modification" for fugitive emissions in the proposed NSPS does not contain this same limitation, and is therefore inconsistent with the current NSPS general provisions. Instead, EPA's overly broad definition would include *all* changes, even those which will have no impact on, or even result in a reduction in, methane emissions. For example, actions such as taking pressure off of the line could increase compression capacity of the station, without increasing emissions. In addition, there is no reason to think that these changes would make the compressor station more likely to have the kind of equipment leaks that the fugitive emissions rules in the proposed NSPS are designed to prevent. Indeed, adding new equipment would likely reduce the likelihood of equipment leaks.

In addition, most compressor stations already operate under air permits, which limit their levels of emissions. As a result, even an increase in "compression capacity" would not result in an increase in emissions above permitted levels. In the past, EPA has also recognized that air emissions that are limited by permitting requirements should be treated differently when considering a facility's potential to emit air emissions. For example, in the New Source Review ("NSR") program, a major source of air emissions may be treated as a synthetic minor source if the actual emissions of the source are limited by the facility's operations to below the major source emissions threshold. EPA's definition of "modification" should also take into account legal restrains on a facility's potential to emit, such as permit restrictions, rather than consider every change in compression capacity to be a "modification." As a result, this definition does not serve its intended purpose of preventing emissions from leaking equipment.

The definition of "modification" for compressor stations is also too vague. Based on the current definition, a number of small changes to a compressor station could inadvertently result in greater "compression capacity" without resulting in additional emissions, and thus trigger the fugitive emissions requirements. This would create uncertainty for the operators of existing stations, who will not know whether they can take certain actions without triggering costly and time consuming leak detection and repair requirements for their entire facility. While the preamble states that EPA adopted this definition "[t]o provide clarity and ease of implementation," in practice it will have the opposite effect and create confusion and frustration for operators.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 40.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 8

Comment: EPA Must More Accurately Define "Fugitive Emission Components" and Clarify the Meaning of Modification in the Context of EPA's Proposed Fugitive Emission Control Requirements

EPA must also clarify the definition of "modification" in the context of the NSPS OOOOa proposed fugitive emission control program. EPA requests comment on whether the "fugitive emission requirements should apply to all fugitive emission components at modified well sites or just those components that are connected to the fractured, refractured or added well." 80 Fed. Reg. at 56638. QEP submits that the fugitive emission control requirements should only apply to those components connected to the modified well.

Consider the following example: operators often add new wells to existing well pads (commonly referred to as infill drilling). These new wells may be on the same pad as existing wells, but often times, the new wells will be connected to separate production trains. Accordingly, under these circumstances, the existing production equipment associated with the existing wells (and not connected to the new wells) should not be brought into the fugitive emission control program.

Therefore, QEP requests that EPA specifically clarify this issue in 40 CFR § 60.5365a(i)(3) by inserting the following bold language to the definition of modification:

(3) For purposes of§ 60.5397a, a "modification" to a well site occurs when:

(i) A new well is drilled at an existing well site **and the new well is tied into the existing well site's production equipment**;
(ii) A well at an existing well site is hydraulically fractured; or
(iii) A well at an existing well site is hydraulically refractured.
80 Fed . Reg. at 56664.

Response: We believe the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site. We believe that defining "modification" to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, EPA is finalizing the definition of "modification" of a well site, as proposed.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 75

Comment: Finally, EPA has undermined the framework of the NSPS program and the Administrative Procedure Act by applying the Methane NSPS to all facilities that are built, modified, or reconstructed after September 18, 2015. As noted above, the NSPS program is designed to address *new* rather than *existing* sources. "New" means "new – *after* a regulation is issued". Otherwise, EPA could regulate all existing sources under the NSPS program, because all sources were new at some point in time. By using the date that the proposed Methane NSPS was published in the Federal Register, rather than the date that the final Methane NSPS is published, EPA has ignored this important constraint on the limits of the NSPS program. Using the date of publication of the proposed, rather than final rule, also undermines the public notice and comment required by the Administrative Procedure Act by effectively telling businesses that their comments will be ignored and that they have no choice but to comply with the rule as proposed. In order for the public to be able to meaningfully comment on a proposal, the proposal cannot begin triggering regulatory requirements before the public has had an opportunity to comment on those requirements.

Response: We disagree with the commenter that we have undermined the framework of the NSPS program and the Administrative Procedure Act by applying the Methane NSPS to all facilities that are built, modified, or reconstructed after September 18, 2015. Section 307(d)(3) of the CAA states that "notice of proposed rulemaking shall be published in the Federal Register, as provided under section 553(b) of title 5, United States Code…." There is nothing in the remainder of section 307(d) that requires the EPA to publish the regulatory text. Similarly, section 553(b) of the Administrative Procedure Act (APA) does not require agencies to publish the actual regulatory text.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 19

Comment: The proposed subpart OOOOa's provisions on what constitutes a modification are confusing in places, in large part because EPA is attempting to define what constitutes a modification of a well, while also identifying what constitutes a modification of a "well site." The definition of what constitutes a modification of a well is relatively straightforward, and not materially different from the application of the same term in subpart OOOO. However, the agency's effort to suggest that drilling a new well at an existing site, or fracturing or refracturing a well at an existing well site thereby brings the entire well site within the purview of the fugitive emissions program raises both legal and operational concerns. The structure of the Clean Air Act suggests that EPA's attempt to broaden the meaning of the term "modification" in this way is problematic, at best. Section 111 of the Act speaks in one subsection to standards of performance for new stationary sources, while another section authorizes the Administrator to determine standards of performance for existing sources.

The logic of the proposed rule suggests that EPA is sweeping too broadly. Throughout the proposed rule, EPA speaks separately about wells, and well sites. It is only when the agency attempts to impose the fugitive emissions control program on existing well sites by virtue of the fact that a new well has been drilled at that site or an existing well has been fractured or refractured that somehow wells and well sites become conjoined.

Noble's experience in the Eagle Ford is far different from its experience in the Denver-Julesburg basin, and illustrates the challenges of adding existing well sites to the fugitive emissions program. Oil and gas production in the Eagle Ford is significantly less dense than is development in places like the Denver-Julesburg basin. In the Eagle Ford, travel to and from a single well site may take an entire day. If existing well sites come within the purview of a fugitive emission program merely because a new well is drilled at an existing site, or an existing well is fractured or refractured, personnel will have to travel as long as a day to conduct a component count and conduct a single survey. In addition, if Noble elects to not train personnel conducting those surveys as certified mechanics- something that may not make sense in the less densely developed eagle Ford-then repair of a leaking component will require at least one additional day for a mechanic to travel to the site and repair whatever leak the surveyor found.

These incremental costs will be accounted for whenever Noble decides whether it makes economic sense to complete a new well at an existing site or to fracture or refracture an existing well. It has been Noble's experience in other basins that those economic considerations may lead to the premature plugging and abandonment of wells that otherwise would contribute to the nation's petroleum supply.

Noble encourages EPA to reconsider its proposal to encompass existing well sites within the purview of the fugitive emissions program and to limit that program to new well sites.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 8.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 71

Comment: Kinder Morgan has specific concerns regarding EPA’s proposed definitions of modification for compressor stations and well sites for the purpose of fugitive emission.

Importantly, EPA proposes that new and modified compressor stations (which include the natural gas transmission and storage segment and the gathering and boosting segment) and well sites conduct fugitive emissions surveys. Thus, if a facility is deemed to be "modified," it would be subject to comprehensive and costly leak detection requirements. As a result, if EPA does not appropriately define "modification," any resulting leak detection requirements would fail to satisfy a positive and balanced cost-benefit analysis.

1. Definition of Modification for the Collection of Fugitive Emissions Components at Compressor Stations and Well-Sites

For purposes of the proposed standards for the collection of fugitive emissions at compressor stations, EPA proposes that a modification to a compressor station would occur when (1) a new compressor is added or (2) when a physical change is made to an existing compressor that increases the compression capacity. Similarly, EPA proposes that modification to a collection of fugitive emission components at a well site be defined as a modification to a well site "only when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured." EPA intends that these proposed definitions of modification at each respective subsection would supersede the general provisions and definition of modification at 40 C.F.R. § 60.14. Kinder Morgan believes that there is confusion in defining the affected facility as a collection of fugitive emission components while simultaneously defining a modification of the affected facility as a change to a compressor station or well site. The definition of modification should be a modification to an actual affected facility. Therefore, Kinder Morgan suggests adding the proposed fugitive monitoring requirements as a required work practice under the already defined affected facilities of centrifugal compressors, reciprocating compressors, and wells. This would accomplish the same fugitive emission reduction goals without introducing a new indistinct affected facility.

Thus, Kinder Morgan proposes EPA eliminate from any final rules its proposed "modification" definitions relating to compressor stations and well sites, and instead apply the general provisions definition of modification at 40 C.F.R. § 60.14 to centrifugal compressors, reciprocating compressors, and wells at both compressor stations and wells sites. Section 60.14 requires three important elements before an event qualifies as a "modification:" (1) a physical or operational change to an existing affected facility, (2) that results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies, and (3) for which a capital expenditure for the affected source. These elements establish the very high threshold necessary to demonstrate a modification has occurred, whereas EPA's proposal undermines these long-standing principles. Moreover, this approach would streamline any final NSPS OOOOa, eliminate confusion, and avoid an overly inclusive definition of modification. Perhaps most importantly, EPA provides no rationale for revising the general applicability criteria and not distinguishing the modified facility from an affected facility. Additionally, as clarified in 40 C.F.R. § 60.14, Kinder Morgan requests EPA clarify that the following shall not, by themselves, be considered modifications under any final NSPS OOOOa:

- Routine maintenance, repair, and replacement;
- An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility;

- An increase in the hours of operation; and
- The relocation or change in ownership of an existing facility.

Any other definition would create implementation issues (specifically with respect to consistency) and regulatory uncertainty.

In addition, the adoption of 40 C.F.R. § 60.14 would be consistent with past and recent EPA rulemakings—which emphasize EPA's long-standing regulatory interpretation of "modification" to require an "increase in the emission rate." In fact, Section 111(a)(2) of the CAA defines "modification" as any physical or operational change at a stationary source that "increases the amount of any air pollutant emitted by such source." Furthermore, in its October 23, 2015 publication of a final rule for "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," EPA clarified that "in general, in order to trigger the NSPS modification or reconstruction requirements, a physical change must increase the maximum hourly emission rate of the pollutant (to be an NSPS modification) or the fixed capital cost of the change must exceed 50 percent of the fixed capital cost of a comparable entirely new facility (to be an NSPS reconstruction)."

If EPA maintains its currently proposed definition of "modification" with respect to compressor stations and the affected facilities, in the alternative, Kinder Morgan proposes the following revisions to EPA's proposed definition of modification with respect to compressor stations:

Proposed Revisions to EPA's § 60.5365a:

(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430a, is an affected facility. For purposes of § 60.5397a, a ''modification'' to a compressor station occurs when:

(1) A new compressor is constructed at an existing compressor station **that results in an increase in the emissions rate(s) of a compressor station**; or

(2) A physical change is made to an existing compressor at a compressor station that increases the compression capacity **and emissions rate(s)** of the compressor ~~station~~.

(3) Reserved

This proposed alternative language would ensure EPA's definition remains consistent with Section 111(a)(2) of the CAA and the purpose and intent of "modification" of an affected facility. Specifically, these proposed revisions ensure not only that the affected facility must increase the amount of any air pollutant emitted to trigger modification, but that the addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of NSPS OOOOa any other facility within that source.

In sum, Kinder Morgan's preferred alternative is for EPA to eliminate its proposed definition of "modification" with respect to compressor stations and wells sites, which is not the affected facility, but use the affected facilities at compressor stations and well sites: centrifugal compressors, reciprocating compressors and wells and adopt the existing Section 60.14 definition of modification as applicable. In the alternative, if EPA maintains its proposed definitions, Kinder Morgan requests EPA revise its definition of modification such that modification only occurs when—through addition of a new compressor or a physical change to an existing compressor at a compressor station—the emissions increase at the compressor affected facility.

Response: We disagree with the commenter regarding the modification definition for well sites. We believe the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells, which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and therefore additional fugitive emission components at the well sites. We also believe that defining "modification" to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, we are finalizing the definition of "modification" of a well site, as proposed.

For compressor stations, we agree with some aspects of the issues raised by the commenter and have made the following revisions to the modification requirements in the final rule. We agree that an increase in the compression capacity that is not due to the addition of a compressor that would result in an increase of the overall design capacity of the compressor station is not a modification. We have also clarified that the installation of a compressor will only trigger the fugitive monitoring requirements if it is installed as an additional compressor or if it is a replacement that is of greater horsepower than the compressor or compressors that it is replacing.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 5

Comment: The definition of "modification" of a well site under the proposed rule is overly broad and may unintentionally bring existing well sites under the proposed rule. Many of the modifications that are included do not increase the likelihood of fugitive releases. EPA should redefine "modification" in §60.5365a(i) and §60.5365a(j) to only include activities which EPA can demonstrate increase the likelihood that a site will have additional VOC or methane fugitive emissions. Alternatively, EPA should revise its definition of "modification" in §60.5365a(i)(3) so that the addition of a well, or fracturing or refracturing of an existing well, only triggers fugitive emission survey requirements if the new or modified well expands the capacity of the well site beyond the original facility throughput design.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 40.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 12

Comment: The definitions of "well site" and "fugitive emissions component" should be clarified to ensure that only emissions that are truly fugitive are the focus of the LDAR program.

- Fugitive emissions are defined at 40 CFR Part 52(b)(20) as: "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." The inclusive definition of "well site" in Subpart OOOOa includes "all ancillary equipment in the immediate vicinity of the well that are necessary for or used in production and may include such items as separators, storage vessels, heaters, dehydrators, or other equipment at the site." The definition of "fugitive emissions component" clearly defines the nature of fugitive emissions from a well site but also references "other openings in storage vessels" and "dehydrators". The definition of fugitive emissions component should be revised to clearly state that emissions from uncontrolled tank vents and uncontrolled dehydrator vents are not fugitive emissions.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 107 and DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 28 concerning the definition of well site. The definition of fugitive emissions component is addressed in the response to EPA-HQ-OAR-2010-0505-6881, Excerpt 10.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 13

Comment: CONSOL supports the exemption of well sites that contain only wellheads from the fugitive emissions provisions of Subpart OOOOa and suggests that the exclusion be expanded. EPA should also consider exempting well sites with fewer than four affected wells.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 109.

Commenter Name: Matthew D. Hall
Commenter Affiliation: Consumers Energy Company
Document Control Number: EPA-HQ-OAR-2010-0505-6862
Comment Excerpt Number: 3

Comment: First and foremost, as outlined in AGA's comments, further clarification is needed on EPA's intent to not impose the proposed standards on intrastate transmission lines. State-regulated Local Distribution Companies (LDCs) operate "transmission lines", as defined by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and 40 CFR 98 Subpart W, within a single state as part of their systems for delivering natural gas to residential and commercial customers. While these intrastate lines are defined by PHMSA to operate at transmission level pressures, they are really part of the LDC's distribution of gas to customers within the state. Consumers Energy urges EPA to exclude LDC-operated intrastate transmission, storage, and distribution pipelines downstream of custody transfer stations where natural gas is transferred to the LDC, and to amend the proposed definition of "natural gas transmission" as indicated in AGA's comments.

This proposal by EPA could, among other things, establish an overly extensive and aggressive fugitive emissions monitoring and repair program for Consumers Energy's existing compressor stations, in their entirety, upon the installation, modification, or reconstruction of a single piece of equipment. Under proposed regulation §60.5365a(j)(2), EPA has attempted to subject the entire compressor station to extensive fugitive emissions requirements if: (1) a new compressor is added, or (2) a physical change to an existing compressor increases station capacity. This attempt to define an entire existing facility as a singular affected unit is entirely inappropriate and inconsistent with existing applicability determinations in other regulations as noted below. Consumers Energy strongly urges EPA to revise this proposal and remove proposed language attempting to define entire existing facilities as a singular affected unit and thus, subject them to an aggressive fugitive emissions monitoring and repair program upon installation, modification, or reconstruction of a singular piece of equipment. This would be costly, onerous and burdensome requirement with minimal environmental benefit.

As stated in the AGA comments submittal, applicability should be triggered based on the accepted, historic, definitions in 40 CFR Part 60: see "modification" in §60.14 and "reconstruction" in §60.15. Upon a verified triggering project, the fugitive emissions requirements should only apply to the affected compressor and its associated components. EPA's attempt to draw an entire compression or storage facility into a fugitive emissions monitoring and maintenance program based on the installation of a new piece of equipment, or a modification/reconstruction of a single piece of existing equipment, is inappropriate.

Response: Concerning local distribution companies, in response to other comments the EPA has finalized the following changes. The proposed rule uses the term "city gate" to delineate the boundary of the natural gas production, processing, transmission, and storage segments (that is, these segments do not extend beyond the city gate). We defined "city gate" in the proposed rule as "the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility." However, a commenter argues that the term "city gate" has various meanings in the industry and the use of the term in the proposed rule creates confusion. While we believe that the term "city gate" is defined appropriately in the proposed rule, based on the various uses of the term provided by the commenter we agree that the term may result in some level of confusion. In order to avoid such confusion, in the final rule we have removed the term "city gate" and replaced it with "local distribution company (LDC) custody transfer station" with the following definition:

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

In addition, we have replaced the term "city gate" with "LDC custody transfer station" in the definition of "crude oil and natural gas source category" in § 60.5430a, which is the only use of the term "city gate" in the proposed rule. We believe these changes adequately address the commenters concerns expressed in the comment above.

Concerning the modification of compressor stations, see the response to DCN EPA-HQ-OAR-2010-0505-6474, Excerpt 7. Concerning the definition of modification in §60.14, see the response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 71.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 12

Comment: For Existing Facilities, Standard "Modification" Definitions Should Apply**.** EPA has proposed that in regard to fugitive emissions from an existing compressor station, a modification occurs either when a compressor is added to the compressor station or when a physical change is made to an existing compressor that increases the compression capacity of the compressor station. AGA appreciates that EPA has proposed this definition of modification to clarify and ease implementation, but believes that EPA's approach should recognize the legal requirement that by definition a "modification" includes a resulting emissions increase. To that end, AGA suggests that for added compressors and physical changes made to existing compressors at an existing facility, the fugitive emissions program should not apply to the entire facility, but instead should only apply to added or altered compressors *that result in an emissions increase* (i.e., meet the definition of "modification").

The Clean Air Act defines "modification" as a change at a source "which results in the emission of any air pollutant." EPA has long required the emissions increase that triggers NSPS applicability to be an increase in emissions of kilograms per hour. Many changes can be made at a compressor station that do not result in an increase in emissions, and, that under the standard definitions, would not trigger NSPS. For example, a new compressor at an existing facility may replace other units or a single, larger unit may replace multiple smaller units. In these instances, emissions may actually decrease from newer equipment or from fewer components with the potential to leak associated with a new compressor. Accordingly, AGA recommends that EPA change this language as follows:

[Note: Underlined text below indicates suggested added language.]

> § 60.5365a(j) . . . For purposes of § 60.5397a, a "modification" to a compressor station occurs when:
>
> (1) A new compressor is constructed at an existing compressor station **that results in a net increase in emissions measured in kilograms per hours from that station**; or
>
> (2) A physical change is made to an existing compressor at a compressor station that **results in an increase in emissions of kilograms per hour** ~~increases the compression capacity of the compressor station~~.

EPA requests comment on whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor. AGA disagrees with EPA's proposal that the collection of fugitive emissions components at a compressor station is an affected facility. AGA recommends that the addition of a compressor at an existing station only should trigger fugitive emissions NSPS requirements for that new compressor if the addition meets the legal definition of "modification," including a resulting emission increase. Along similar lines, for upgrades to an existing compressor, fugitive emissions requirements should only apply to the affected compressor if the change meets "modification" criteria.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 71.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 6

Comment: EPA Must Revise and Clarify Key Definitions

A. Definition of "Modification" for Compressor Stations

We appreciate EPA's attempt to simplify how to define modification for fugitive emissions at compressor station sites. However, there are instances where this definition would encompass changes at compressor stations that do not result in increased emission rates. The CAA defines a modification for purposes of the NSPS program as:

Any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

42 U.S.C. § 7411(a)(4). "This definition requires both a change—whether physical or operational—and a resulting increase in the emission rate of a pollutant." New York v. EPA, 413 F.3d 3, 11 (D.C. Cir. 2005) (emphasis in original); see also Environmental Defense v. Duke Energy Corp, 549 U.S. 561, 567 (2007) ("an NSPS modification" is "a change that "increase[s] … the emission rate,' which 'shall be expressed as kg/hr of any pollutant discharged into the atmosphere.'" (quoting 40 C.F.R. § 60.14(b))). Under this two-part standard for modification, it is not enough for a facility to simply make physical or operational changes. To qualify as a modification, those changes must necessarily result in an increase in emission rates.

EPA's generally applicable definition in the NSPS program is consistent with the statute and the D.C. Circuit's case law and states:

Any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

40 C.F.R. § 60.14(a). As stated in this definition, the touchstone of a modification is an increase in emission rate. Consistent with the statute, if there has not been an increase in emissions, then, by definition, there has not been a modification. In other words, the act of making physical changes to a source does not—by itself—constitute a modification.

In the proposed rule, EPA introduces a new definition of "modification" for compressor stations that is unduly broad and inconsistent with the generally applicable definition of modification in the NSPS program. The definition of modification is significant here, as all existing components at a compressor station site would become subject to regulation if changes at the site triggered the proposed definition of modification, See 42 U.S.C. § 7411(a)(2). Not just the new or modified equipment. Here, EPA proposes two conditions under which a modification could occur:

(1) A new compressor is constructed at an existing compressor station; or (2) A physical change is made to an existing compressor station that increases the compression capacity of the compressor station.

Proposed 40 C.F.R. § 60.5365a(j).

EPA's part (2) of this definition includes physical changes that, by definition, would constitute a modification that triggers NSPS for existing compressor stations even in the absence of an increase in emission rate: an increase in compression capacity. This is a deviation from the foundation of the statutory text and generally applicable modification definition without cause. This condition set out in the proposed rule will not necessarily result in an emissions increase and should not be considered a modification without some evidence that an emissions increase will occur. EPA fails to provide any justification for expanding the definition of modification to include equipment changes that do not necessarily lead to an increase in emissions. Nor can it. It is a well-established principle of administrative law that "[w]here Congress has established a clear line, the agency cannot go beyond it." City of Arlington v. FCC, 133 S. Ct. 1863, 1874 (2013). Congress did establish a clear line by requiring an emissions increase for modifications under the NSPS program and EPA cannot go beyond the statute by eliminating that requirement.

In addition, several terms in EPA's proposed definition of modification are ambiguous. The term "new compressor" can be construed to mean a different compressor and/or an additional compressor. Moreover, the term "compression capacity" is unclear and could potentially be based on a gas flow rate, compression power, or some other unit of measure. The maximum gas flow rate for compressor(s) at a compressor station can vary significantly depending on the inlet and outlet pressures, temperatures, and gas composition. For example, a compressor may be able to move a lot more gas starting from an inlet pressure of 200 pounds per square inch ("psi") up to 800 psi than starting from 50 psi to get to 800 psi.

Further, GPA urges EPA to clarify that a "like-kind" replacement does not constitute a "new compressor" for purposes of triggering a modification. From time to time, existing compressors at a compressor station must be replaced due to age, wear, or a number of other reasons. In such situations, a new compressor is simply exchanged for the existing compressor with no associated change in operations or throughput at the facility. In this sense, a like-kind replacement of a compressor at an existing compressor station does not add anything new to the compressor station and makes no changes to the manner in which a compressor station operates. Simply put, a like-kind replacement does not meet the definition of modification included in Section 111(a) of the CAA or in EPA's generally applicable regulations. Thus, to provide certainty to operators and avoid the risk of unnecessary enforcement actions, EPA must clarify that replacing an existing compressor with a new compressor does not constitute a modification under 40 C.F.R. §60.5365a(j) as GPA has suggested in the revised definition above.

Therefore, to ensure that the definition of modification is based on an increase in emission rates required by the CAA and to remove ambiguity, EPA must revise the definition of modification in 60.5365a(j) to read as follows:

(1) An additional new compressor, except a like-kind replacement, is constructed at an existing compressor station and the rate of fugitive emissions increases from the compressor station, or
(2) A new compressor, with a higher fugitive emissions rate, replaces an existing compressor.

This definition captures EPA's intent for a modification to only be triggered when an additional new compressor is constructed, and also captures the CAA requirement of an increase in emission rate. To be clear, onerous fugitive component counts should not be required to determine if an emissions increase has occurred. Operators are familiar with calculating fugitive emissions as part of air permit applications, and also have the option to use EPA's approach based on major equipment types in 40 C.F.R. 98, Subpart W. Indeed, there is already precedent in NSPS OOOO for using generally accepted emission calculations for fugitive emissions. See

40 C.F.R. § 60.5495 ("The uncontrolled actual VOC emissions [from a storage vessel] must be calculated using a generally accepted model or calculation methodology.").

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 71.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 113

Comment: The Definition Of Modification For Leak Detection Under §60.5365a(i)(3) Is Flawed For Both Well Sites And Compressor Stations.

Well Site Modification

EPA has defined a modification for well site fugitives as follows in §60.5365a(i)(3)

"For purposes of §60.5397a, a "modification" to a well site occurs when:

i. a new well is drilled at an existing well site;

ii. a well at an existing well site is hydraulically fractured; or

iii. a well at an existing well site is hydraulically refractured."

Increasing production by drilling a new well or hydraulically fracturing an existing well does not increase the probability of a leak from an individual component and no new components result from these activities, thus the potential emissions rate does not change. EPA appears to agree, as there is no demonstration in this proposal, the TSD, or RIA that shows increased fugitive emissions from higher pressures. EPA's estimate of emissions simply uses the accepted method of component count × AP-42 factor.

The increased emissions from hydraulic fracturing are accounted for in the requirements for control devices and closed vent systems for storage vessels. Potential changes in pressure from hydraulic fracturing would only be on the components for the well head because components from the well choke or separator help to regulate the line pressure to that of the gathering system. Furthermore, for safety reasons, the components at the well head and down the line are rated for higher pressures beyond what wells and gathering systems will operate, and an increase in the pressure alone would not inherently impact the emissions from those components.

Compressor Station Modification

EPA has defined "modification: for compressor stations in §60.5365a(j):

For purposes of § 60.5397a, a ''modification'' to a compressor station occurs when:

(1) A new compressor is constructed at an existing compressor station; or

(2) A physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

Here, EPA presumes that the addition of a new compressor at an existing compressor station would automatically increase the compressor station's emission rate and meet the definition of "modification". This is very often <u>not</u> the case – an operator may install a new compressor at an existing site to replace one or more existing compressors, which may even reduce emissions. In addition, an increase in compression capacity does not necessarily include a commensurate throughput and potential fugitive emission rate increase, it may simply be added for redundancy to increase operating reliability of the station. Throughput increases can also occur without increasing the number of compressors, if increases remain below the capacity of currently installed compressors.

Complicating matters, "new" means construction commenced after the proposal date. In this case construction refers to manufactured date. Since "new" compressors aren't new because of when they are installed but rather when they are manufactured, "new" compressors may be relocated to other sites when no longer needed at current sites to save incurring capital costs of purchasing a newly manufactured compressor. This may also be a "new" or existing rental compressor if not expected to be on location long enough to justify a purchase of a new or existing compressor. Consequently, if a capital expenditure occurs, it will generally only be when the "new" compressor is initially installed. Relocating a "new" compressor from one site to another is often an expense, but not a capital expenditure. Paragraph 60.5397a(j)(1) is then based on a flawed premise to presume that a site modification has occurred. The "new" compressor may already be subject to Subpart OOOOa requirements, but was installed without incurring a capital expenditure. Coupled with situations for adding compression that do not incur an emissions increase as described in the previous paragraph, no modification occurs, and it is inappropriate to presume otherwise.

Similarly, presuming a physical change that increases compression capacity increases emissions is also flawed. Increasing capacity doesn't necessarily mean an increase in throughput or an emissions increase in fugitive emissions. Capacity of one compressor may be increased so that another compressor can be permanently shutdown or relocated as part of a site optimization project which generally results in emissions decreases. In this case, a disincentive is presented in Subpart OOOOa by requiring a leak detection program for a project designed to decrease emissions, not increase.

Use of Modification in Other Rules

As with NSPS OOOO and NSPS KKK, it has historically been and should continue to be EPA's intent that triggering NSPS through "modification" is in fact a difficult threshold to meet, not an easy one. Here, however, EPA's proposed definition is overly inclusive and inappropriately relaxes the definition of modification.

The Clean Air Act Section 111(a)(4) defines a modification as follows -"The term ''modification'' means any physical change in, or change in the method of operation of, a stationary source which **increases the amount of any air pollutant emitted** by such source or which **results in the emission of any air pollutant not previously emitted**." [emphasis added]

Also §60.2 defines modification as: "Modification means any physical change in, or change in the method of operation of an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted."

The original definition of modification in §60.14 includes an increase in hourly emission rates. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere."

§60.14 require three important elements before an event qualifies as a "modification":

(1) a physical or operation change to an existing affected facility,

(2) that results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies, and

(3) for which a capital expenditure is required. These elements establish the very high threshold necessary to demonstrate a modification has occurred, whereas EPA's proposal undermines these long-standing principles.

§60.14(e)(2) states that "*an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility*" is not a modification. EPA has defined in this rule the affected facility as a "well site" and the definition of a "well site" does not include the well bore or reservoir that is being fractured. "*Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at §60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).*"

Hydraulic fracturing is not a capital expenditure for the well site as it does not involve physical changes or changes to the operation of existing surface equipment. It is the process of "fracturing" the reservoir. A new well bore is subsurface and not part of the "well site" which is a surface site. Therefore, EPA should not consider the addition of a new well or hydraulically fracturing an existing well a modification for a facility for the purposes of LDAR.

Furthermore, other NSPS for fugitives (e.g., VVa and GGGa) define the affected facility by the process unit and requires a capital expenditure to be a modification to the process unit. VVa defines the affected facility as "*the group of all equipment within a process unit*" (§60.480a(a)). Equipment is defined as "*each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart (§60.481a).*" VVa also states that "*Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.*" VVa defines capital expenditure differently too giving a much higher B value of 12.5 vs. 4.5.

GGGa defines the affected facility as (§60.590a(a)):

(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in §60.591a) within a process unit is an affected facility. Under GGGa, equipment is defined as "Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment." (§60.591a) Process Unit is defined as "the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482-1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart." (§60.591a) It states that "Addition or replacement of equipment (defined in §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart."

Recommendation

EPA's cost analysis was based on a model plant with certain component counts (554 for gas wells and 135 for oil wells). API recommends that the definition of modification be based on the addition of certain large equipment such as a separator, heater, or dehydrator, as used for the model plant count basis, to be consistent with the basis of the cost analysis and other fugitive rules. Furthermore, replacement of existing equipment should not be considered a modification to the facility since it would not increase the component count which is what the cost estimate is based on.

Response: We disagree with the commenter regarding the modification definition for well sites. We believe the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells, which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and therefore additional fugitive emission components at the well sites. We also believe that defining “modification” to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, we are finalizing the definition of “modification” of a well site, as proposed.

For compressor stations, we agree with some aspects of the issues raised by the commenter and have made the following revisions to the modification requirements in the final rule. We agree that an increase in the compression capacity that is not due to the addition of a compressor that would result in an increase of the overall design capacity of the compressor station is not a modification. We have also clarified that the installation of a compressor will only trigger the fugitive monitoring requirements if it is installed as an additional compressor or if it is a replacement that is of greater horsepower than the compressor or compressors that it is replacing.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 115

Comment: Recommended Rule Text and Definition Revisions Based on Comments in this Section

§60.5365a(i) Except as provided in § 60.5365a(i)(1) through (i)(~~2~~5), the collection of fugitive emissions components at a new, modified, or reconstructed well site, as defined in § 60.5430a, is an affected facility. 1) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production or for any 12 consecutive month period after startup of production, is not an affected facility under this subpart.

(2) Any well site or process unit with a GOR less than 300 scf/bbl during the first 30 days of production or for any 1 year period after startup of production is not an affected facility.

(3) Any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system is not an affected facility.

(4) Well sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.

(~~2~~5) A well site with one or more wellheads that does not ~~only contain~~ include installation of at least one of the following: a separator, heater, or glycol dehydrator ~~one or more wellheads~~ is not an affected facility under this subpart.

(6) A well site that produces oil with either an API gravity less than 18˚or a GOR less than 300 scf/bbl is not an affected facility under this subpart

(7) An EOR wellsite is not an affected facility under this subpart

(~~3~~8) For purposes of § 60.5397a, a ''modification'' to a well site occurs when an additional well head, separator, heater, or dehydrator is installed.

~~(i) A new well is drilled at an existing well site;~~

~~(ii) A well at an existing well site is hydraulically fractured; or~~

~~(iii) A well at an existing well site is hydraulically refractured.~~

§60.5365a(j) The collection of new, modified, or reconstructed fugitive emissions components at a central production site or transmission compressor station site, as defined in §60.5430a, is an affected facility. The collection of fugitive emissions components at a compressor station or central production site in an EOR field is not an affected facility.

(1) Central production sites and transmission compressor station sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.

(2) For purposes of § 60.5397a, a ''modification'' to a compressor station or central production site occurs when:

(i) An additional new, modified, or reconstructed compressor is installed at an existing transmission compressor station or central production site that results in an increase in emissions of a compressor station or central production site; or

(ii) A physical change is made to an existing compressor at a transmission compressor station or central production site that increases the ~~compression capacity of~~ emissions at the transmission compressor station or central production site.

(iii) An additional new, modified, or reconstructed separator, heater, or dehydrator is installed at a central production site.

§60.5430

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir.

Recommended definition changes:

Central production site means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.

Fugitive emissions component means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. ~~any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive~~ emissions.

"Well site means one or more contiguous ~~areas~~ surface sites that are ~~directly~~ constructed ~~disturbed during~~ for the drilling and subsequent operation of an oil or natural gas well, and any ~~affected by~~ production facilities directly associated with any oil well or natural gas well. ~~or injection well located on a well pad. For the purposes of the fugitive emissions standards at §60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).~~

Response: We appreciate the suggested revisions by the commenter, but we believe that the changes that we have made are appropriate and clarify the requirements for the final rule.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 15

Comment: If EPA employs TPA's proposed site-screening approach, it would eliminate many of the flaws that we believe are present in EPA's currently proposed fugitive emissions requirements. In the event that EPA decides to retain its current approach, however, we submit the comments in subparagraphs (a)-(g) below in order to address those flaws and to provide suggestions as to how EPA could improve its currently proposed requirements.

The proposed definition of "modification" for purposes of the fugitive emission requirements at compressor stations should be revised to focus on emissions increases, not increases in compression capacity.

EPA proposes a special definition of "modification" that would apply when determining whether a modification has occurred at a compressor station, thus triggering application of the proposed fugitive emissions requirements for compressor stations. That definition would provide that a modification occurs when (1) a new compressor is constructed at an existing compressor station; or (2) a physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

This proposed "modification" definition is too broad and is focused on the wrong thing. The rules should not provide that a modification occurs simply because there has been a change that increases compression capacity. Many events could increase compression capacity, without increasing emissions, *e.g.* taking pressure off of the line, or changes in ambient air temperature. Rather, the focus should be changes that result in increases in *emissions*.

Maintaining a focus on emission increases in the definition of "modification" would keep the rules consistent with Section 111 of the Clean Air Act, which defines "modification" to mean "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." Similarly, the definition of "modification" in the NSPS general provisions (40 CFR § 60.14) focuses on the presence of emissions increases, *as* well *as* capital expenditures. Defining a modification so that an emissions increase is needed to satisfy the definition would have the benefit of keeping the focus of the new rules on reducing emissions, which is the whole purpose of new OOOOa and the NSPS / Clean Air Act rules in general, a point made by EPA in proposing amendments to the NSPS general provisions in 1974:

> The proposed amended definition of "modification" also includes a new phrase "...emitted into the atmosphere ...." The new phrase clarifies that for an existing facility to undergo a modification there must be an increase in actual emissions. If any increase in emissions that would result from a physical or operational change to an existing facility can be offset by improving an existing control system or installing a new control system for that facility, such a change would not be considered a modification because there would be no increase in emissions to the atmosphere.... ***[T]he proposed definition of modification is limited to increases in actual emissions in keeping with the intent of section 111 of controlling facilities only when they constitute a new source of emission***.

Accordingly, TPA suggests a revision to the proposed "modification" definition providing that, for a modification to be found, there would have to be *inter alia* a change resulting in an emissions increase.

TPA also suggests that the concept of "design-rated" capacity be added to the definition's reference to increased compression capacity. This would ensure that modifications under the rule were limited to increases in capacity that were the result of mechanical changes to the compressor itself, rather than external changes that might result in increased capacity. For example, re-wheeling a centrifugal compressor is a mechanical modification that increases the design-rated capacity of the compressor and as such it is appropriate that such a change could constitute a "modification" under the rule. However, *as* noted above, external factors such *as* changes in ambient temperature or changes in pipeline or inlet pressure may also increase a compressor' s compression capacity, but such changes should not be considered "modifications" under the rule because they are not changes to compressor equipment and in some cases they are completely beyond the control of the compressor station's owner or operator. Making a modification contingent on a change in the compressor's design-rated capacity would make clear that capacity increases resulting from such external factors would not be considered "modifications" under the rules.

Finally, the definition of "modification" in this context should incorporate all of the exceptions set forth in 40 CFR § 60.14(e), which provide that certain activities or increases are not considered to constitute modifications. These limited exceptions have the benefit of carving out activities and changes that do not properly fit the category of a "modification' ' that could potentially trigger NSPS application; moreover, the exceptions have worked well in practice and we see no basis for EPA's proposal to eliminate the applicability of these exceptions in the context of compressor station fugitive emissions.

Based on the foregoing comments, we suggest that proposed 60.5365a(j) be revised as follows:

(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430 is an affected facility. For purposes of § 60.5397 a "modification" to a compressor station occurs when:

1. A new compressor is constructed at an existing compressor station; or
2. A physical change, <u>including a replacement,</u> is made to an existing compressor at a compressor station that increases <u>both</u> the <u>maximum design-rated</u> compression capacity <u>of the compressor and the amount of emissions from</u> ~~of~~ the compressor ~~station~~.
3. ~~Reserved~~ The provisions of 40 CFR § 60.14(e) shall apply to this subsection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 40.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 17

Comment: TPA believes that application of the Subpart OOOOa fugitive emission requirements in this situation must be limited only to those fugitive sources that are connected to the new or modified compressor. This limitation would be in keeping with the whole point of NSPS rules, which is to address and limit emissions from "new" sources of emissions. EPA has correctly recognized this in the past; in proposing amendments to the NSPS general provisions in 1974, EPA wrote:

> The proposed amendments clarify that the construction of an affected facility at a stationary source does not constitute a modification of the stationary source and *does not cause the entire stationary source to become subject to the standards of performance.* As an example, *the addition of a new basic oxygen process furnace to an existing furnace shop which includes two furnaces, would not make the entire steel mill or the two existing furnaces subject to standards of performance; only the new furnace would be subject to standards of performance.*

The same approach should be taken by EPA now. To impose Subpart OOOOa's requirements on all of the existing fugitive emissions sources at a compressor station -including sources not connected to the new or modified compressor -simply because there was an isolated modification or addition somewhere at the facility, would be tantamount to implementing an *ESPS* for those non-connected sources, *i.e.* an existing source performance standard, not an NSPS. Congress drew a bright line, with different procedural mechanisms, controls, and standards, for new source rules under Section 111(b) vs. existing source rules under Section 111(d). Section 111(b) creates a federal program whereby EPA sets standards for new sources, while Section 111(d) creates a state-based program whereby EPA establishes guidelines and states then design programs that fit in those guidelines to obtain required emission reductions. EPA should not subject existing sources to NSPS standards where those existing sources cannot fairly be considered to have been newly added or modified.

Response: We agree with some aspects of the issues raised by the commenter with respect to compressor stations and have made the following revisions to the modification requirements in the final rule. We agree that an increase in the compression capacity that is not due to the addition of a compressor that would result in an increase of the overall design capacity of the compressor station is not a modification. We have also clarified that the installation of a compressor will only trigger the fugitive monitoring requirements if it is installed as an additional compressor or if it is a replacement that is of greater horsepower than the compressor or compressors that it is replacing.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 28

Comment: The proposed definitions of fugitive emissions at modified well sites and compressor stations should be amended. 80 Fed Reg. at 56, 664. Well completions from hydraulic refracturing are not an affected source under NSPS OOOO, and therefore, a modification to a well site should not include a well that is hydraulically refractured. This revision will provide consistency with the well completion provisions. In addition, a physical change to an existing compressor at a compressor station may not be accompanied by an increase in components.

Therefore, the definition of modification to a compressor station should not include a physical change to existing equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 40.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 11

Comment: For Existing Facilities, Standard "Modification" Definitions Should Apply.

EPA has proposed that in regard to fugitive emissions from an existing compressor station, a modification occurs either when a compressor is added to the compressor station or when a physical change is made to an existing compressor that increases the compression capacity of the compressor station. AGA appreciates that EPA has proposed this definition of modification to clarify and ease implementation, but believes that EPA's approach should recognize the legal requirement that by definition a "modification" includes a resulting emissions increase. To that end, AGA suggests that for added compressors and physical changes made to existing compressors at an existing facility, the fugitive emissions program should not apply to the entire facility, but instead should only apply to added or altered compressors that result in an emissions increase (i.e., meet the definition of "modification").

The Clean Air Act defines "modification" as a change at a source "which results in the emission of any air pollutant." EPA has long required the emissions increase that triggers NSPS applicability to be an increase in emissions of kilograms per hour. Many changes can be made at a compressor station that do not result in an increase in emissions, and, that under the standard definitions, would not trigger NSPS. For example, a new compressor at an existing facility may replace other units or a single, larger unit may replace multiple smaller units. In these instances, emissions may actually decrease from newer equipment or from fewer components with the potential to leak associated with a new compressor. Accordingly, AGA recommends that EPA change this language as follows:

§ 60.5365a(j) . . . For purposes of § 60.5397a, a "modification" to a compressor station occurs when:

(1) A new compressor is constructed at an existing compressor station that results in a net increase in emissions measured in kilograms per hours from that station; or

(2) A physical change is made to an existing compressor at a compressor station that results in an increase in emissions of kilograms per hour ~~increases the compression capacity of the compressor station~~.

EPA requests comment on whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor. AGA disagrees with EPA's proposal that the collection of fugitive emissions components at a compressor station is an affected facility. AGA recommends that the addition of a compressor at an existing station only should trigger fugitive emissions NSPS requirements for that new compressor if the addition meets the legal definition of "modification," including a resulting emission increase. Along similar lines, for upgrades to an existing compressor, fugitive emissions requirements should only apply to the affected compressor if the change meets "modification" criteria.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 71.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 13

Comment: Definition of "Modification" at a compressor station for purposes of fugitive emission standard. WBI Energy recommends that EPA apply the definition of "modification" in 40 CFR 60.2 to this source category. A modification should result in an increase in the amount of an air pollutant emitted. In the definition proposed in the rule, a modification at a compressor station occurs "when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station". WBI Energy recommends this be amended to reflect that the modification must result in an increase in emissions rather than an increase in capacity. It may be possible that a change could be made to a compressor at the facility that increases capacity but does not necessarily increase the potential to emit at the facility.

§60.5365a(j) - Definition of "Modification" to a Compressor Station

- See previous comments. WBI Energy recommends applying the definition of a modification in 40 CFR 60.2 to these facilities. A modification should result in an increase in emissions, not capacity from a compressor unit.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 71.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 2

Comment: The proposed regulation should cover new and modified sources only. The proposed definition of "modification" is not consistent with the current regulation and potentially expands the scope of the proposed regulation to existing sources, which is outside of the scope of the New Source Performance Standard (NSPS) for new and modified sources. We recommend that EPA revise the definition of "modification" to make it consistent with existing definitions in the NSPS.

In the draft regulation [40 CFR §60.5635aG)], a compressor station is considered to be "modified", if

(a) a new compressor is constructed at an existing compressor station or

(b) a physical change is made to an existing compressor at a compressor station that increased the compression capacity of the compressor station.

The definition of modification in the proposed regulation is not consistent with that in the current General Provisions of the NSPS [40 CFR §60.14(a)], which defines modification as

"any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies ... "

First, the current draft regulation definition of modification of fugitive components at a compressor station is based solely on the changes associated with the compression capacity at the station; so the affected emissions equipment or process (i.e., fugitive components) is different from that used in the applicability determination. Secondly, the test for modification assumes that with the increase in compression capacity, irrespective of the magnitude of increase, would result in an emissions increase from the fugitive components. We request that the definition of modification for existing compressor stations be revised to be consistent with the definition of modification in §60.14(a). It is highly possible that the addition of new compression equipment and/or replacement of existing equipment at a facility may actually reduce methane emissions from the facility. As such the definition of modification should account for increase in fugitive emission rates (kg/hour) from new components and/or new compression equipment and should not be based solely on an increase in compression capacity.

Alternatively, and preferably, EPA should simply refer to the existing definition of modification [40 CFR Part 60, §60.14(a)] within this draft regulation and refrain from modifying existing established regulatory statute in this proposed revision to Subpart OOOO.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 71.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 30

Comment: While it is true that EPA can provide for deviations from the general modification definition in a particular subpart, it does not follow that EPA can define a modification more broadly than the statutory provisions would allow. The definition of modification in CAA Section 111(a)(4) limits "modifications" to changes that result in an increase in the amount of an air pollutant emitted or which result in the emission of an air pollutant not previously emitted. Thus, in order to consider the proposed listed activities automatically to be a modification, EPA must establish that those activities will by definition cause an emissions increase (as defined in the NSPS regulations) or emission of a new pollutant.

The analysis in the proposal does not establish the requisite increase. A fundamental requirement of rulemaking is that an agency properly support and explain its factual conclusions. It is well established that in rulemaking, an "agency must examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" Here, EPA bases its cost analysis and proposed standards for fugitive emissions from well sites and compressor stations on fugitive emissions factors from Publication AP-42. Those AP-42 emission factors are based on the number of components in service and not on the pressure or volume flow of the fluids within those components.

Refracturing a well does not categorically mean that emissions will increase. Indeed, EPA should revise the definition of "modification" for well sites to *exclude* refracturing of a well. Since fugitive emissions are determined using emission factors that are based on the number of each component and the service (gas, heavy oil, light oil and water/oil) and not on the pressure or volume flow rate of the fluid contained within those components, the proposal's factual conclusion that increasing pressure increases emissions from the affected facility is incorrect.

Moreover, refracturing a well, which is subsurface work, does not necessarily result in the addition of "fugitive emission components" (*i.e.*, in that adding fugitive components could increase emissions). Subsurface physical activity should not affect surface fugitive emissions unless there is an accompanying surface activity that would cause an increase in emissions. A physical change in, or change in the method of operation of, an existing well's surface equipment does not necessarily occur as a consequence of refracturing. In addition, refracturing may only maintain the production rate at a well, which would not increase the production rate beyond existing equipment capacity. Thus, refracturing should not be considered a "modification."

This conclusion is further supported by the General Provisions for Part 60, which exclude from the definition of modification an "increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility." Since refracturing does not require a capital expenditure, it should not be considered a "modification."

With respect to compressors and compressor stations, fugitive emissions from the collection of fugitive emissions components at a station are a function of the number of such components, not compression capacity. Any change to a compressor that does not result in a net addition of fugitive emissions components should not be a modification because no increase in emissions would occur.

Finally, EPA's rationale for its proposed "modification" provisions for fugitive emissions components at well sites and compressor stations is inconsistent with equipment leak provisions in other NSPS, including Subpart OOOO. Specifically, Subpart OOOO and the proposed Subpart OOOOa regulate the group of all equipment, except compressors, within a process unit within a natural gas processing plant. Under proposed Section 60.5365a(f)(1), the "[a]ddition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart." Capital expenditure is defined in proposed Section 60.5430a. The addition of some new equipment (valves, flanges, connectors, etc.) does not necessarily result in NSPS applicability for a gas plant. EPA did not include similar language for its proposed fugitive emissions standards for well sites and compressor stations. EPA's component-based approach in the proposal conflicts with the group-based approach in the gas plant provisions. A similar provision should apply to well sites and compressor stations. EPA should provide the option to owner/operator that if a piece of process equipment is added, specifically, a dehydrator unit, process heater, storage vessel, or separator, that would be considered a modification, unless the source owner or operator showed that a capital expenditure was not required.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 71.

Commenter Name: Josh Nordquist
Commenter Affiliation: Ormat Technologies
Document Control Number: EPA-HQ-OAR-2010-0505-7059
Comment Excerpt Number: 4

Comment: Recommendation 2: Regarding the definition of "modification." On page 120-121 of the final rule, EPA proposes that a "modification" of a compressor station only occurs when a compressor is added or when a physical change is made to increase the compression capacity of the compressor station. Ormat supports this definition. The addition of auxiliary equipment to enable a waste heat to power operation should not be considered a "modification" under the final rule.

Response: The EPA appreciates the commenter's support on this issue.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 49

Comment: EPA has Broad Authority to Define Modifications.

Section 111 of the Act defines a "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source[.]"42 U.S.C. § 7411(a); *see also Evtl. Defense v. Duke Energy Corp.*, 549 U.S. 561 (2007). The regulatory definition in EPA's General Provisions implementing Section 111 provides that a "modification" is "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies …." 40 C.F.R. § 60.14(a).

Consistent with the plain terms of the statute and implementing regulations, the General Provisions also recognize that EPA is not bound to these exceptions and instead has ample authority to define "modification" in particular rules consistent with the statute. Such definitions "shall supersede any conflicting provisions of this section," i.e., any of the listed exceptions. *Id.* § 60.14(f). Indeed, in the 1974 rulemaking establishing the separate regulatory section for modifications in the NSPS program, EPA noted that the legislative history supporting section 111 "allows considerable latitude in interpreting phrases in the definition of modification such as 'stationary source' and 'increases the amount of any air pollutant emitted.'" 39 Fed. Reg. at 36,946.

In past NSPS rulemakings, EPA has exercised its robust statutory authority to adopt definitions for particular source categories. These include past actions to address emissions from the oil and gas sector, where EPA, citing the statutory definition, determined that re-fracture of a hydraulically fractured natural gas well constituted a modification requiring application of reduced emission completion technology. 77 Fed. Reg. 49,490, 49,511. The agency explained that in order to fracture an existing well during recompletion, re-perforation of the well causes physical change to the wellbore and casing. The process therefore results in a physical change to the wellhead, the affected facility subject to NSPS, as well as an increase in emissions. Proposed Rule, 76 Fed. Reg. 52,738, 52,745 (Aug. 23, 2011). EPA has taken a similar approach to defining modification for flares at petroleum refineries, *see* 40 CFR § 60.100a(c), and for municipal solid waste landfills, *see* 40 CFR § 60.751.

Courts have upheld EPA's broad approach to the Section 111 modification provisions. *See Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 905, 909 (7th Cir. 1990) (noting the potentially broad reach of the modification requirements and concluding "[n]or can we find any support in the relevant case law for the narrow constructions of 'modification' and 'physical change [put forward by petitioners]'"); *cf. Envtl. Defense*, 549 U.S. at 565 (overturning decision requiring EPA to define "modification" consistently for purposes of the NSPS and Prevention of Significant Deterioration ("PSD") program and noting that a rigid application NSPS modification definition in the PSD context "was inconsistent with [the PSD provisions] and effectively invalidated them").

EPA's Authority Clearly Encompasses the Activities the Agency has Defined as Modifications.

EPA has concluded that (1) drilling a new well; (2) re-fracturing a well; and (3) adding or making a physical change to a compressor at a compressor station are modifications. For well sites, the agency provides the following rationale for its determination:

When a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well.

80 Fed. Reg. at 56,614. Similarly, for compressor stations, the agency notes:

Since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components.

Id. These activities fit within the statutory definition of modification: they are clearly physical or operational changes, and evidence demonstrates that such increases in production, system complexity, and compression are associated with increased emissions. In particular:

- System Complexity. In the production sector, "the number and type of equipment that could be potential leak sources generally scales with the number of wells."
- Increases in Production. In the production sector, gas production rates have been found to have a weak positive correlation with methane emissions. In the gathering and processing sector, absolute methane emissions are generally higher at facilities with larger throughput (although emissions can represent a greater percentage of total throughput at smaller facilities). Also in this sector, throughput differences explain a portion of methane emissions from gathering facilities. Moreover, Colorado tiers LDAR requirements based on actual uncontrolled tank emissions, which are tied to increases in throughput and, in a recent rulemaking, EPA itself has recognized that routing a new well to a storage tank can increase emissions from the storage vessel. Proposed Rule, 78 Fed. Reg. 22,126, 22,131, 22,139 (Apr. 12, 2013).
- Increases in Pressure. In the gathering and processing sector, "[t]he variation in methane emissions appears driven by differences between inlet and outlet pressure, as well as venting and leaking equipment." Also in this sector, "[t]he magnitude of some fugitive leaks scale with pressure."

EPA Should Identify Additional Activities as Modifications.

Other activities have many of the same attributes as the actions EPA has proposed to identify as modifications. In particular, EPA should clarify that well workovers with hydraulic fracturing are the same thing as a completion with hydraulic fracturing, and thus a modification. Further, EPA should designate (1) well workovers with acidizing or re-perforation; (2) the installation of an additional compressor engine at a well site; and (3) the addition of other equipment, including dehydrators, that are a potential source of fugitives as activities constituting modifications for purposes of inclusion in LDAR requirements.

Well workovers that include the use of hydraulic fracturing constitute both physical and operational changes, satisfying the section 111(a)(4)'s definition of modification. These physical and operational changes at the well site are invasive procedures requiring a significant capital expenditure, and are conducted only when the existing well's production is faltering. EPA, the Wyoming Department of Environmental Quality, and the American Petroleum Institute have presented evidence identifying a number of non-routine workover procedures. Moreover, hydraulic fracturing is proven to cause an increase in emissions from the wellsite. And well workovers with and without hydraulic fracturing have been shown to cause comparable emissions: in a study of direct measurements of workover emissions, Allen. et al. found that potential emissions from flowback following a workover without hydraulic fracturing "are of the same order of magnitude as the EPA estimated value of 4.2 million scf for workovers with hydraulic fracturing."

Like workovers with hydraulic fracturing, well workovers with acidizing and with re-perforating are treatments used to return a low-functioning well to productivity. Well acidizing, a form of fracturing using acid, typically involves pumping acid into the wellbore to remove formation damage, improving permeability and flow—the acid dissolves sediments that inhibit permeability to increase the effective well radius. Re-perforating, including adding shallower or deeper perforations in a well's cement liner or casing, is the process of clearing the wellbore and perforation holes that have been clogged by sediment.

Both types of workovers clearly cause a physical change to the wellbore and casing, and therefore a physical change to the wellhead, within section 111(a)(4)'s definition of 'modification.' These activities also result in increased fugitive emissions throughout the affected facility from production rate increases.

The installation of an additional compressor engine at a well site should also be considered a modification. EPA has specifically identified the addition of a compressor as a modification of a compressor station. 80 Fed. Reg. at 56,614. It should qualify as a modification in other segments, including the production segment. As EPA noted, "expansion of compression capacity . . . through addition of a compressor . . . would result in an increase in emissions." *Id.* The addition of a compressor at a well site is a physical change that causes an increase in pressure as well as an increase in system complexity, both of which increase fugitive emissions. Compressors, as sources of vibration and heat, are associated with significant fugitives – as shown in Table 1 *supra*, 54% of all leaks from aboveground sources in the oil and gas industry originate from compressors. An additional compressor brings with it an increase in leaks from the gas supply lines that feed it and an increase in pressure throughout the system, which causes amplify emissions from associated equipment. Similarly, the addition of dehydration equipment at either a well site or compressor station should be considered a modification of the facility.

Response: We appreciate the input provided by the commenter and have made some changes to the modification definitions. We believe that the changes achieve our original goal of having clearly identifiable criteria that can be easily recognized by operators and regulators.

Commenter Name: Jeff Addington, Manager Air Quality
Commenter Affiliation: Archrock Services, L. P. and Archrock Partners Operating LLC ((individually and collectively, ArchRock)
Document Control Number: EPA-HQ-OAR-2010-0505-6944
Comment Excerpt Number: 4

Comment: EPA has not defined "permanent" in the context of this definition. For purposes of determining applicability of this part of the rule, "permanent" should not include portable or transportable compressors, such as those that are designed to be (e.g., skid-mounted) and that are capable of being moved from one location to another. EPA has used similar criteria when determining which engines are not subject to the RICE rules. See 40 C.F.R. § 1068.30. "Indicia of transportability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform." *Id*. Equipment with such characteristics should not be subject to the requirements in NSPS OOOO or OOOOa because they are not permanent.

Similarly, only the construction of a new permanent compressor at an existing compressor station or a physical change to an existing permanent compressor at a compressor station that increases the compression capacity of the compressor station should constitute a "modification" to that compressor station. The use of an additional, modified or reconstructed portable or transportable compressor should not trigger a modification.

Archrock supports EPA's focus on the permanence of this equipment because the rule proposes that new compressor stations and modified compressor stations would need to begin monitoring within 30 days of construction or a modification. If the use of temporary or portable equipment could trigger the requirement to conduct such surveys, the burden associated with such monitoring and recordkeeping would potentially be significantly greater than what EPA intended (i.e., annual, semi-annual or even more frequent fugitive emissions surveys).

Response: We are finalizing that a modification to a compressor station occurs when a compressor is added to a compressor station or if one or more compressors is replaced with one or more compressors with a greater total horsepower. For the purposes of determining whether a compressor is permanent, we believe the definition in §1068.30 provide criteria for determining if a compressor is portable or permanent. Based on this criteria, a compressor is permanent if the compressor remains or will remain at a location for more than 12 consecutive months.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 37

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 33

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 34

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 34

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 35

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 34

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 29

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 23

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 28

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 25

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 24

Comment: EPA should exempt operators from the fugitive survey requirements in the Methane NSPS if they are in compliance with the equipment control requirements in Subpart OOOO or Subpart OOOOa, and have a performance-based internal company program designed to detect leaks annually and repair the leak within 30 days of detection.

Response: The final rule is designed to complement current state and other federal regulations. We carefully evaluated existing state and local programs when developing these federal standards and attempted, where practicable, to limit potential conflicts with existing state and local requirements. However, we recognize that in some cases these rules require more stringent regulatory provisions and in other cases may be less stringent than current state rules. After careful consideration of all of the comments, we are finalizing the standards with revisions were appropriate to expand the source category, promote gas capture and beneficial use, and provide opportunity for flexibility and expanded transparency in order to yield a consistent and accountable national program that provides a clear path for states and other federal agencies to further align their programs. See section III.E of the preamble to the final rule and discussion in the State LDAR comparison Memo in the Oil and Natural Gas docket for more detail regarding this issue. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 8

Comment: In order to reduce the impact of these regulations while still providing for protection of the environment, the TCEQ supports the EPA's proposed exemptions for low production well sites, and encourages EPA to provide additional exemptions for other scenarios where possible. The TCEQ supports the proposed exemptions for low production well sites of less than 15 barrels of oil equivalent or less per day (BOEPD) and sites with less than 300 SCF/bbl gas-to-oil (GOR) ratio. The TCEQ also encourages the EPA to establish other exemptions from the regulations for small oil and gas sites based upon reasonable limited emissions and/or equipment with any tank or vent limited to less than 6 tpy on an uncontrolled basis. An example of an exemption for a site based upon low emissions would be a case where any vent or tank would have to have an uncontrolled emission rate of less than 6 tpy, and total site emissions of less than 8 tpy. Exempting sites with a small number of fugitive components (such as fewer than 100 fugitive components and fewer than 50 components when any other tank or vent emission rate is less than 6 tpy total) is another example of a limitation based upon equipment which the EPA could include. An additional approach would be to exempt sites with 3 or fewer pieces of equipment, with any vent or tank emissions limited to less than 6 tpy total. This would be a site with only a well head, a separator, and a heater treater or a tank. Loading trucks would count as one piece of equipment. The TCEQ emphasizes that even small sites exempted by these NSPS would still be required to obtain authorization from the TCEQ for their production emissions and maintenance, startup, and shutdown emissions.

Response: We did not receive additional data on equipment or component counts for low production wells, and we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This indicates that the emissions from low production well sites are similar to that of non-low production well sites. We also believe that this type of well may be developed for leasing purposes but are typically unmanned and not visited as often as other well sites which would allow fugitive emissions to go undetected. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. We have retained the exemption for a well site that only contains one or more wellheads.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 31

Comment: Should EPA insist that wells and tank batteries producing oil still be subject to LDAR, then a threshold should be set that is scalable to the potential to emit. For example, a tank battery that handles less than 20,000 mcfd has little potential to leak significant volumes of natural gas. The gas leaked from these sized facilities would be minimal and a LDAR survey would yield little benefit.

Response: We disagree with the commenter and have determined that semiannual monitoring was BSER for oil and natural gas well production sites. These well sites have the same equipment and components and therefore the same potential to emit fugitive emissions.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 47

Comment: As an alternative, should EPA insist that wells and tank batteries producing oil still be subject to LDAR, then a threshold should be set that is scalable to the potential to emit.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6849, Excerpt 31.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 78

Comment: The final Methane NSPS should only apply to sources built, modified, or reconstructed after the final rule is published in the Federal Register.

Response: Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources that, in his or her judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue "standards of performance" for new sources in such source categories. Standards of performance under section 111 are issued for new, modified and reconstructed stationary sources. These standards are referred to as "new source performance standards." Section 111(a)(2) defines "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." Based on this definition, the EPA must use the date of publication of the proposed regulation as the defining date for new sources if the proposed regulation is published earlier than the final regulations. Therefore, the commenters are incorrect in their assertion that the rule should apply only to facilities modified or constructed after the date of publication of the final rule.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association

Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 100

Comment: The Methane NSPS states that it would apply to any facility that was new, modified, or reconstructed after the proposed Methane NSPS appeared in the Federal Register on September 18, 2015. EPA has introduced new definitions of "modification" for portions of the Methane NSPS, and may further alter those definitions before the rule is finalized. As previously discussed in this comment, those definitions are also problematically broad and vague. This puts members of the oil and gas industry in an unfair situation, as they may inadvertently trigger the requirements in the Methane NSPS by making a "modification" to a facility under a version of the definition that has not yet been finalized or clarified.

Given the potential impact of the Methane NSPS, it is not at all unlikely that EPA will spend substantial time responding to all of the public comments and revising the rule before it is finalized. The final Methane NSPS is also likely to face challenges in court that could further delay the implementation of this rule. Existing facilities frequently require maintenance work and updates to their equipment. Until the Methane NSPS is finalized and completed, operators will not know whether they can make certain alterations to their existing facilities without suddenly triggering the NSPS requirements, and thus cannot plan for the necessary compliance costs and personnel hiring that they will need for their facilities.

Recommendation: EPA should only apply the Methane NSPS to facilities that are built, modified, or reconstructed after the effective date of the rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6849, Excerpt 78.

Commenter Name: Dan G. LeRoy
Commenter Affiliation: Legacy Reserves Operating LP
Document Control Number: EPA-HQ-OAR-2010-0505-6882
Comment Excerpt Number: 14

Comment: EPA's decision to make the Methane NSPS apply retroactively to all facilities modified or reconstructed after September 18, 2015, but prior to the issuance of the final rule, raises due process and notice concerns.

The Methane NSPS states that it would apply to any facility that was new, modified, or reconstructed after the proposed Methane NSPS appeared in the Federal Register on September 18, 2015. EPA has introduced new definitions of "modification" for portions of the Methane NSPS, and may further alter those definitions before the rule is finalized. As previously discussed in this comment, those definitions are also problematically broad and vague. This puts members of the oil and gas industry in an unfair situation, as they may inadvertently trigger the requirements in the Methane NSPS by making a "modification" to a facility under a version of the definition that has not yet been finalized or clarified.

Given the potential impact of the Methane NSPS, it is not at all unlikely that EPA will spend substantial time responding to all of the public comments and revising the rule before it is finalized. The final Methane NSPS is also likely to face challenges in court that could further delay the implementation of this rule. Existing facilities frequently require maintenance work and updates to their equipment. Until the Methane NSPS is finalized and completed, operators will not know whether they can make certain alterations to their existing facilities without suddenly triggering the NSPS requirements, and thus cannot plan for the necessary compliance costs and personnel hiring that they will need for their facilities.

Recommendation: EPA should only apply the Methane NSPS to facilities that are built, modified, or reconstructed after the effective date of the rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6849, Excerpt 78.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 5

Comment: The Division provides the following comments on specific elements of the proposed NSPS OOOOa LDAR program.

a. Centralized facilities

The Division has found that some operators in Colorado are moving towards large, centralized facilities, which are associated with the well but may also have natural gas compressors. These facilities have fewer emissions (e.g., no storage tanks), but do not fit nicely into EPA's proposed definitions of a compressor station site or well site. The Division requests that EPA clarify whether EPA would consider such a centralized facility as a well site or a compressor station. If EPA chooses not to specifically define these types of facilities, the Division requests that EPA support the Division's determination as it relates to applicability under NSPS OOOOa in Colorado.

Response: We cannot make a determination without having more information about the types of equipment or design of these centralized facilities.

Commenter Name: Joshua M. Kindred
Commenter Affiliation: Alaska Oil & Gas Association (AOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6879
Comment Excerpt Number: 4

Comment: In authoring any oil and gas related regulations, the EPA should account for the unique aspects of Alaska operations, particularly given the unique logistical and meteorological variables that are inescapable. The North Slope of Alaska is the area between the Brooks Range and the Arctic Ocean. It is entirely above the Arctic Circle and is located about 400 miles north of the closest major population center, Fairbanks. From a logistical standpoint, only one road connects the North Slope oil fields to population centers in the interior. Furthermore, many North Slope oil fields lack road access altogether, and, thus, the primary access for personnel is by air. These logistical realities are further complicated by frequent interruptions due to fog-grounded flights and road closures due to various weather-related complications, which can often last for weeks. As a result, operations must allow for an adaptive schedule to accommodate for these transportation interruptions and complications.

Response: In developing the requirements for the final rule, we have tried to add flexibility in the dates for fugitive emission requirements accommodate the remote nature of these sites. We believe this flexibility is also appropriate for sources in the North Slope of Alaska and believe that no further changes are needed. In the final rule we have incorporated a waiver for owners or operators that have compressor stations in areas of the country that have an average monthly temperatures below 0°F (based on historic climate data). If two of three months of a quarterly monitoring period each have an average temperature below 0°F, fugitive emissions monitoring is waived for that quarter.

Commenter Name: Laura K. Perry, Coordinator - Air Quality
Commenter Affiliation: ConocoPhillips Alaska, Inc. (CPAI)
Document Control Number: EPA-HQ-OAR-2010-0505-6947
Comment Excerpt Number: 3

Comment: The EPA has acknowledged in prior rulemaking processes that Leak Detection and Repair (LDAR) requirements should not be applied to the North Slope because the balance of feasibility, benefit, and cost is different under Arctic conditions. For similar reasons CPAI asks EPA to exempt North Slope operations from the LDAR requirements of the proposed OOOOa rule.

The reasons for an exemption are set forth fully in the attached detailed comments, and can be summarized as follows:

- The technology required does not always reliably work finding methane leaks under the prevailing conditions on the North Slope.
- The prescriptive schedule for methane leak detection and repairs of the LDAR requirements in the proposed OOOOa imposes a greater burden on the North Slope compared to non-Arctic locations. The extreme and lengthy winter weather conditions and remote nature of the North Slope along with the logistical difficulties presented by both make the leak detection schedules and repair timelines frequently untenable.

- The shutdowns that may be required to fix some leaks could result in millions of dollars per day in lost gross revenue, which would deprive the State of Alaska from its main revenue source and dramatically affect other stakeholders.
- All above-ground piping and valves in oil production service are required by the State of Alaska to be visually inspected at least once per month for leaks. This means that personnel inspect equipment for leaks from the wellhead all the way into the processing facilities for leaks. Piping containing production fluids, whether liquid or gas, is all above ground on the North Slope, except for the unflanged piping that must cross roads and pads.
- Alaska North Slope processing facilities are manned 24 hours per day, 7 days per week, and 365 days per year. Alaska North Slope drill sites are visited daily, weather permitting. Practices are in place to detect and repair leaks at processing facilities and drill sites.

Because most of the flanged oil production equipment is enclosed and in containment, methane leaks cannot be generally tolerated on the North Slope. In short, the goals of a methane leak detection and repair program are not going unaddressed on the North Slope as evidenced by the leak detection and repair program already in place that is adapted to the North Slope conditions. These prescriptive rules are not consistent with that existing program, however, and CPAI believes that if the existing program was substituted with the leak detection and repair program in the proposed OOOOa rules, it would be a step backward.

Response: We disagree that North Slope operations should be exempt from the fugitive emissions requirements in subpart OOOOa. To address some of the concerns raised by the commenter, we have made some revisions to the final rule to address these issues. The revisions include: allowing the use of a Method 21 analyzer to monitor components, extending the time to perform repair to 30 days, allowing 30 days for resurvey, and allowing up to 2 years for repair of components that would require a well shut-in. We believe that the fugitive emission requirements in the final rule, in conjunction with current Alaska requirements, can significantly reduce methane and VOC emissions from North Slope operations.

Commenter Name: Laura K. Perry, Coordinator - Air Quality
Commenter Affiliation: ConocoPhillips Alaska, Inc. (CPAI)
Document Control Number: EPA-HQ-OAR-2010-0505-6947
Comment Excerpt Number: 3

Comment: Alaska's North Slope – its Climate and Meteorological Impacts on Logistics. The North Slope of Alaska is the area between the Brooks Range and the Arctic Ocean. It is entirely above the Arctic Circle and is located about 400 miles north of the closest major population center, Fairbanks. There is one road that connects this population center to some North Slope oil fields while other North Slope oil fields have no road connection at all. Thus, the primary access to the North Slope for workers is by air. These road and air connections to our major support centers are characterized by frequent interruptions due to spring breakup related flooding and weather-grounded flights, the former of which can last for weeks. As such, schedule adaptation is a frequent necessity, project delays are not uncommon, and personnel have learned to be resilient in their transportation expectations. During the periods when they are physically on the North Slope, workers face additional challenges.

The climate of the North Slope is harsh, marked by persistently low wintertime temperatures, consistent winds, and a sun that remains below the horizon for about two full months per year. North Slope-specific weather data, collected just south of the Alpine field, shows that for about five months of the year, the average temperature is below 0°F (Figure 1).

[Note: Figure 1 (2012-2014 Average Hourly Temperature (°F), Nuiqsut, AK) illustrates the discussed cold weather data.]

Related, snow is typically on the ground on the North Slope from about September to June each year. This is important because, as can be seen in Figure 2, winds in excess of 10 miles per hour occur more than 40% of the year causing periods of blowing snow and reduced visibility. This can frequently result in what is referred to on the North Slope as "phase" conditions, where the oil industry implements ground travel restrictions for the purpose of safety. Phase conditions can occur on more than 30% of the days in the months October to May.

[Note: Figure 2 (Nuiqsut Wind Speed Histograms; note wind speeds in excess of 10 mph for 11,596 hours of the 26,304 hours covering the three-year period) presents hours and wind speed data for years 2012 through 2014.]

From the above, it is relatively easy to see that the North Slope winters are indeed harsh. The shoulder seasons also have their challenges given the intense pressure gradients seen in the fall with the onset of winter and the aforementioned issues associated with spring breakup such as the Dalton Highway flooding. But the short summer season also has its challenges.

Figure 3 below shows the amount of time the main airport into the North Slope oil fields, Deadhorse (PASC), was subject to various flight rules based on meteorological conditions between 1973 and 2007. Of note, during the months June through September, the airport was subject to low instrumental flight rules (LIFR) or very low instrumental flight rules (VLIFR) slightly more than 20% of the time. VLIFR accounted for about 1/3rd to 1/4th that amount of time. LIFR applies to conditions where cloud ceilings are less than 1,000 feet and visibility is less than 1 mile. VLIFR applies to conditions where cloud ceilings are less than 500 feet and visibility is less than ½ mile. The Federal Aviation Administration identifies VLIFR conditions as a criterion for closing airports.

[Note: Figure 3 (Deadhorse Airport Flight Categories, 1973-2007) presents VLIFR conditions as a percent of PASC occurrences.]

For comparison, Figure 4 is the corresponding plot for the Ted Stevens Anchorage International Airport (PANC). Note that the flight challenges are so different for the two that they are plotted on different scales.

[Note: Figure 4 (Anchorage Airport Flight Categories, 1973-2004) presents VLIFR conditions as a percent of PANC occurrences.]

To summarize, climatic and meteorological conditions on Alaska's North Slope are such that, no matter the season, the best made plans have to be flexible in their scheduling and that delays in achieving goals are quite often inevitable. In 2013 and 2014, North Slope flights using Boeing 737 jet aircraft were delayed an average of more than once per week. Flights to the satellite fields using smaller aircraft from the Deadhorse hub are similarly challenged. Each delay has a "daisy-chain" effect on subsequent flights so schedule recovery can take time. The weather on the North Slope and the effect it has on logistics must be taken into account when crafting rules with tight schedules for compliance. In addition, as explained elsewhere in these comments, the North Slope weather can also force limitations on the technology associated with an LDAR program.

Oil Production on the North Slope of Alaska. Figure 5 is a conceptual overview of North Slope operations. There are multiple drill sites which are connected via multi-phase pipelines (containing oil, water, and gas) to a central processing facility. Separation of the produced fluids occurs at the central processing facility, not at the drill site. Figure 6, a map depicting the layout of the drill sites that feed into Kuparuk's Central Processing Facility No. 3 (CPF3), is typical of North Slope oil production operations. Figures 7 and 8 are aerial photographs of CPF2 and a typical drill site.

[Note: Figure 5 (Simplified diagram of North Slope oil production facility).]

A drill site (of which six are depicted above), consists of the wellheads (anywhere from 10 to more than 70) which are enclosed in small well houses, manifold buildings where each individual well's production is commingled into a common pipe flowing from the gravel pad toward the processing facility, sometimes a production heater to prevent produced water from freezing, metering, and tanks that store materials that are not produced fluids (e.g., methanol for well freeze protect). In Kuparuk and Alpine, there are more than 50 drill sites containing over 1,700 wells. Except when wells are being completed or having maintenance performed on them, there is no active fluid separation at the drill sites. During normal production operations, all fluids separation occurs at the processing facilities.

At the centralized processing facilities, produced sales quality crude oil is not stored as one might find in the tank batteries common in the Lower 48 states. The produced sales quality oil is piped directly from the processing facility to Pump Station 1, the beginning of the TransAlaska Pipeline System (TAPS), where the oil is piped to Valdez, AK for shipment. There are large divert oil tanks (approximately 55,000 bbl each) at some facilities. These divert tanks are used for emergency situations (e.g. when a pump station unexpectedly shuts down and cannot accept oil). During such a time, the produced oil will accumulate in these tanks and they will be emptied back into the pipeline when normal operations resume. A small amount of oil (approximately 10% or less by volume) may occupy these tanks at any given time, however this oil is cycled out of the tank either on a weekly or monthly basis, depending on the tank. These tanks are equipped with a vapor recovery system.

[Note: Figure 6 (Map of Kuparuk's CPF3).]

The processing facilities receive all the produced fluids from a drill site, separate them into their water, gas, and oil phases, and route the gases and water back to the reservoirs, using some of the gas as fuel for the facility equipment (i.e., the gas is not processed for sale). The processing facilities are fully manned around the clock, are almost entirely enclosed, and consist of the separators, the equipment necessary to route fluids to their destination, such as pump, turbine-driven compressors, and notably, power generation equipment. The processing facilities, working together, produce only sales quality crude oil, are remote from civilian infrastructure, and must be self-contained. Moreover, because they are all enclosed and manned, liquid and gas leaks cannot be generally tolerated so the facilities (and manifold buildings at the drill sites) contain gas detection equipment that alert operators to leaks so they may be expeditiously repaired. When conditions allow, drill site operators make daily trips to the drill sites to, among other tasks, inspect for leaks so they may also be expeditiously repaired.

[Note: Figure 7 (Typical Central Processing Facility).]

[Note: Figure 8 (Typical Drill Site Overview).]

Employees work in shifts on the North Slope, generally two weeks on and two weeks off. They are transported to the facilities via air and are provided room and board while at the facilities. The production of crude oil in the state of Alaska is regulated by the *Oil and Other Hazardous Substances Pollution Control* provisions found at 18 AAC 75. For oil production facilities, these regulations require, among other things, monthly checks for leaks:

Since all production fluid piping on the North Slope is above ground (except for the welded pipe under road and pad crossings) and that produced gas and oil piping are routed together, this means all the piping, whether in produced fluid or gas service, is checked for leaks at least monthly. Different operators have different schedules for adhering to this requirement, with some doing it even more frequently than monthly, but it is safe to say that these checks are conducted much more frequently than the semi-annual checks required by the proposed OOOOa. When methane leaks are detected during these checks, workers are instructed to generate work orders so they may be investigated and repaired. Leak detection and repair are an integral part of North Slope oil production operations.

Response: We appreciate the information provided by the commenter.

Commenter Name: Laura K. Perry, Coordinator - Air Quality
Commenter Affiliation: ConocoPhillips Alaska, Inc. (CPAI)
Document Control Number: EPA-HQ-OAR-2010-0505-6947
Comment Excerpt Number: 3

Comment: Technical, Logistical, and Commercial Infeasibility of Applying the Proposed Scheduled LDAR Requirements to the North Slope of Alaska. There are four major issues with applying the proposed and scheduled LDAR requirements on Alaska's North Slope:

- Optical gas imaging (OGI) cameras are specified to work in temperatures above -4°F;
- Performing methane leak detection at each of our 50+ drill sites and 1,700+ wells on a rigid schedule will be challenged by meteorological conditions;
- Completing repairs of methane leaks in the time allotted by the proposed rule will be at times infeasible, setting us up for situations of non-compliance; and
- The commercial impacts associated with repairing leaks that require more than 15 days to fix could be excessively burdensome.

According to FLIR Systems, Inc., the optical gas imaging cameras' operating temperature range is from -4°F to 122°F. This manufacturer does not offer any gas imaging cameras designed to operate in temperatures below -4°F. From Figure 1, it is seen that temperatures below -4°F are obviously a common occurrence on the North Slope, rendering wintertime LDAR activities technically infeasible since not all enclosures are heated, and most above-ground piping is exposed. In addition, our experience indicates that attempts to perform methane leak detections activities using the OGI technology in wind speeds greater than 8 miles per hour produces unreliable results.

Further, Figures 1 and 2 (temperature and wind plots), and the fact that there is typically snow on the ground from September to June, show that the proposed methane leak detection schedules can only reliably be carried out in the summer months. The new rule should not impose a methane leak detection schedule that is known to be impractical to meet.

The proposed repair deadline of 15 days also poses a problem. Though a large inventory of spare parts is maintained on the North Slope, it is neither practical nor possible to keep on hand all the parts that may conceivably be needed to repair a future methane leak. Some repairs might thus require parts to be purchased and shipped in from outside the North Slope. Figure 3, the plot of Deadhorse airport flight rule categories, shows that getting the parts on a reliable schedule (i.e., within 15 days), no matter the time of year, is not a given. We acknowledge that the proposed rule allows more time to repair the methane leak if repairing it with 15 days is "technically infeasible or unsafe" but are not certain that flight delays would fit into this extension allowance. Thus, again, we foresee difficulty in complying with the rule as proposed.

In some cases, methane leaks on North Slope facilities would inarguably be "technically infeasible or unsafe" to repair in 15 days, in which case the proposed repair deadline of six months or the next scheduled shutdown, whichever is sooner, would apply. But even that extended deadline imposes a disproportionate burden on the North Slope, especially for minor leaks, and would in some cases cause more emissions than it would prevent. Some leaks may require a shutdown to repair and, if a shutdown is not already scheduled within six months of detecting the leak, then a previously unscheduled process shutdown will have to occur. A process shutdown is a time consuming, labor intensive, expensive, and broadly impacting endeavor. For example: pipelines must be de-inventoried and surveyed, gas will be flared, diesel engines will have to be started to provide utilities (because the facilities normally run off natural gas separated from the oil), gas-fired equipment will have to be shut down and subsequently started up, and wells will be shut in (ranges from 250 to 535 wells depending on the facility). The emissions associated with this gas flaring, diesel use, and equipment shutdown-startup cycle are much greater than the emissions resulting from methane leaks. We do not believe this scenario is consistent with the proposed rule's goals.

Moreover, royalties and taxes on North Slope oil production is the major revenue stream to the State of Alaska, which would be significantly and adversely affected by any previously unscheduled shutdowns for the purpose of repairing methane leaks, even minor ones. CPAI produces sales quality crude oil from its production facilities, and production volume varies by facility. If a processing facility was to engage in a previously unplanned shutdown to perform fugitive emission leak repair, lost production revenue would range from a gross of $2.6 million to $5.2 million per day (based on a crude oil price of $50/bbl) depending on which facility was shut down. If a drill site must be shut down to repair a leak, the gross lost revenue could be in the hundreds of thousands of dollars per day. We do not believe economic impacts this large are either contemplated by or warranted by the proposed OOOOa.

In sum, oil production on the North Slope is distinct from production elsewhere in the United States. The facilities are inter-connected and flow to a single pipeline that routes all the produced crude oil from the North Slope to market, there are dozens of wells at each drill site, most of the facilities are enclosed and manned around the clock, and the operations occur in the context of logistical and climatological challenges that are unique. Given this, as well as the aggressive leak detection and repair programs already in place on the North Slope, we request that the prescriptive LDAR requirements found in the proposed OOOOa rule be made explicitly not applicable to Alaskan North Slope oil production facilities and drill sites. Compliance with the rule is impractical and unduly costly, and there are other measures in the place on the North Slope that would make any benefit of complying with the proposed rule requirements either negative or small.

Response: We agree with the commenter that OGI cameras are not designed to operate in subzero temperatures, but believe that are months during the semiannual monitoring periods that the OGI camera can work effectively. We have also included provisions in the final rule for the use of Method 21 analyzers to monitor components. In addition, we have extended the time to perform repair to 30 days and allow another 30 days for resurvey. In some cases, we have also extended the time for repairs that would require a well shut-in up to 2 years. We believe these revisions will prevent unscheduled shut-ins, and therefore not affect the revenue stream to the State of Alaska. We acknowledge that at certain temperatures, an OGI instrument may not operate properly or at all. Therefore, in the final rule we have incorporated a waiver for owners or operators that have compressor stations in areas of the country that have an average monthly temperatures below 0°F (based on historic climate data). If two of three months of a quarterly monitoring period each have an average temperature below 0°F, fugitive emissions monitoring is waived for that quarter.

Commenter Name: Laura K. Perry, Coordinator - Air Quality
Commenter Affiliation: ConocoPhillips Alaska, Inc. (CPAI)
Document Control Number: EPA-HQ-OAR-2010-0505-6947
Comment Excerpt Number: 3

Comment: Prior EPA Decisions around Applying LDAR Requirements to North Slope Facilities. EPA has previously recognized the difficulties in applying prescriptive LDAR requirements to the facilities on the North Slope of Alaska. Because of these difficulties, exemptions from prescriptive LDAR requirements appear in the following rules:

- 40 CFR 60, Subparts GGG and GGGa: Standards of Performance for Equipment Leaks of VOC on Petroleum Refineries
- 40 CFR 60, Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants
- 40 CFR 60, Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (exemption only for Natural Gas Processing Plants)
- 40 CFR 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities (exemption only for Natural Gas Processing Plants)

The basis for the exemptions was first seen in the preamble for GGG. EPA wrote:

> *EPA has studied the commenter's concerns and acknowledges that there are several unique aspects to refining in the North Slope of Alaska. Accordingly, EPA concluded that the costs to comply with the routine leak detection and repair requirements of the proposed standards may be unreasonable. These operations incur higher labor, administrative, and support costs associated with leak detection and repair programs because: (1) They are located at great distances from major population centers, (2) they must necessarily deal with the long-term, extremely low temperatures of the arctic, and consequently (3) they must provide extraordinary services for plant personnel. These unique aspects make the cost of routine leak detection and repair unreasonable (Document Number IV-B-15). Therefore, EPA has decided that refineries in the North Slope of Alaska are exempt from the routine leak detection and repair requirements of the standards.*

This view is evidently carried forward into the proposed OOOOa rule since Alaskan North Slope Natural Gas Processing Plants are exempted at §60.5401a(e) from the same LDAR provisions the above listed rules require. Since the climatological and logistical conditions that exist at the Natural Gas Processing Plants are the same as those at the surrounding drill sites and production facilities, the drill sites and production facilities should also be exempted from the prescriptive monitoring requirements and repair schedules.

Response: We appreciate the information from the commenter, but disagree that operations in the North Slope should be exempted from the requirements in subpart OOOOa.

Commenter Name: Joshua M. Kindred
Commenter Affiliation: Alaska Oil & Gas Association (AOGA)

Document Control Number: EPA-HQ-OAR-2010-0505-6879
Comment Excerpt Number: 8

Comment: Fugitive Emission Repair Requirements. AOGA believes that the proposed schedule for repair requirements relating to a source of fugitive emissions that is technically infeasible or unsafe to repair or replace during operation of the unit is unreasonable given the significant safety, integrity, and flaring consequences unique to oil and gas operations in Alaska. EPA's proposal mandates that the source of fugitive emissions shall be repaired or replaced during the next scheduled shutdown or within 6 months, whichever is earlier. Provided the geographic and seasonal realities of the Alaskan North Slope, oil and gas operators schedule large separation facilities shutdowns during the summer months. Given the litany of plausible scenarios that could result in a separation facility being required to shut down in order to fix a leak in late fall, winter, and early spring, AOGA is compelled to stress that such shutdowns will result in greater safety and integrity concerns. In addition, AOGA notes that the flaring of between 250,000 MMscf and 500,000 MMscf of gas during shutdowns may be an unintended and unavoidable consequence of the proposed rule. Simply stated, the emissions release associated with shutting down a production facility; shutting in and freeze protecting wells; and depressuring and purging the necessary equipment will result in far greater emissions than are being released from the leak that could be repaired during the next scheduled process shutdown. In addition to the increased safety concerns and counter-productive flaring, implementing the repair requirements as currently drafted will also result in severe economic repercussions. Every day of a non-summer shutdowns will result in millions of lost revenue for operators, which, in turn, will lead to substantial lost revenue for Alaska. It is not clear to AOGA whether the EPA accounted for the significant costs associated with this aspect of the proposed rule.

AOGA would advocate that the EPA include an exemption for North Slope operations, similar to such North Slope LDAR exemptions that the EPA has included in the past. For example, the EPA has included exemptions in: (1) NSPS Subpart GGG/GGGa: Standards of Performance for Equipment Leaks of VOC on Petroleum Refineries; (2) NSPS Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants; (3) NSPS Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (exemption only for Natural Gas Processing Plants); and (4) MACT Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities (exemption only for Natural Gas Processing Plants). The EPA has acknowledged the unique aspects of North Slope oil and gas operations in these prior exemptions, concluding that "that the costs to comply with the routine leak detection and repair requirements of the proposed standards may be unreasonable." In doing so, the EPA noted that North Slope operations "incur higher labor, administrative, and support costs associated with leak detection and repair programs because: (1) They are located at great distances from major population centers, (2) they must necessarily deal with the long-term, extremely low temperatures of the arctic, and consequently (3) they must provide extraordinary services for plant personnel. These unique aspects make the cost of routine leak detection and repair unreasonable."

The annual cost of repairing the gas leaks (that are differentiated from fugitive emissions based on the Lower Explosion Limit) at one facility is an additional $250,000. Based on the ambiguity of the definitions of "well site" and "compressor station" in the current rule, this company estimates the cost of the OGI survey requirements alone as a result of the rule could range from $2MM - $8MM annually.

Given that the realities of North Slope operations remain unchanged, it is reasonable for the EPA to follow the same reasonable and equitable approach that it has in past regulations.

One of our member companies currently spends approximately $1MM annually on an LDAR program using OGI to identify de minimus fugitive emissions and gas leaks on the North Slope.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6947, Excerpt 3.

Commenter Name: Joshua M. Kindred
Commenter Affiliation: Alaska Oil & Gas Association (AOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6879
Comment Excerpt Number: 7

Comment: **De Minimis Fugitive Emission Threshold.** The definition of fugitive emissions in 60.5397a has too low of a threshold and includes de minimus fugitive emissions. For purposes of this section, fugitive emissions are defined as: any visible emission from a fugitive emission component observed using optical gas imaging (OGI). An OGI infrared camera will detect light hydrocarbon gases when there is a difference in temperature between the gas and the background. On the North Slope of Alaska in an enclosed module which is an atmospheric controlled environment, there is a greater ability for the OGI survey to detect fugitive emissions. An OGI survey conducted outdoors will be impacted by wind that will dissipate the accumulation of gas and reduce the detection capabilities. EPA should differentiate between de minimus "fugitive emissions" and "gas leaks," especially if the OGI survey is conducted in an enclosed module or building.

Response: We agree with the commenter and have revised the definition of fugitive emissions as; any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using Method 21. The use of a Method 21 analyzer will allow the company flexibility in the type of system used to find and repair fugitive emissions.

Commenter Name: Joshua M. Kindred
Commenter Affiliation: Alaska Oil & Gas Association (AOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6879
Comment Excerpt Number: 5

Comment: The unique structures and methodologies utilized for oil and gas production on Alaska's North Slope highlight potential flaws in the implementation of OOOOa provided the ambiguous definitions of both "well site" and "compressor station." Given the proposed definitions of those two terms, it is likely that there are many facilities in Alaska that could reasonably be captured by either definition, which surely runs contrary to the EPA's intent. As written there is no EPA provision that prohibits compressor stations from being defined as well sites, an issue discussed in more detail below.

Separation facilities in Alaska can operate as a gas gathering and boosting station, using compressors to move natural gas through gathering pipelines to a natural gas processing facility. As a result, such separation facilities meet Subpart OOOOa's definition of a "compressor station". However, these separation facilities also operate as tank batteries storing hydrocarbon and produced water liquids. Therefore, such separation facilities also meet Subpart OOOOa's definition of a "well site."

This dual-qualification of Alaska separation facilitates is not without consequence. EPA expressly provides for the definition of "well site" to broadly include all ancillary equipment in the "immediate vicinity of the well" that are necessary for or used in production. As relevant to oil and gas operations on Alaska's North Slope, the ancillary equipment at the separation facility is customarily geographically removed from the well site, anywhere from one to twelve miles. This would not appear to meet the definition of "immediate vicinity" as it relates to a "well site."

AOGA contends that, for the purposes of the fugitive emission standards under §60.5397a, the definition of "well site" should not include tank batteries that collect oil or other hydrocarbon liquids, or produced water from wells not located on the same pad or site. AOGA encourages the EPA to consider defining "well site" as a site containing one or more oil wells, natural gas wells, or enhanced oil recovery injection wells, while also providing that ancillary equipment only be considered as part of a "well site" if it is truly in the immediate vicinity of the well(s).

In addition, only sites with major equipment (such as compressors and storage vessels) should be subject. The proposed requirement to exempt sites with only wellheads is not adequate. §60.5365a(i)(2) exempts well sites that only contain one or more wellheads. AOGA believes an LDAR program at well sites with only wellheads and without process equipment is overly burdensome and has little benefit due to the small number of fugitive components and emissions.

Response: The commenter expressed concern that the unique and extreme conditions found at the Alaska North Slope leads to equipment configurations not found elsewhere in the United States. For example, a site may have several well heads that are all connected by a pipeline to a separation facility that may be located miles away. A compressor is typically used to move natural gas through the pipelines to the separation facility. The separation facility may also contain tank batteries storing hydrocarbon liquids and produced water. The commenter argues that the wording of the definition of "well site" could be interpreted to mean that the tank battery is a well site.

Concerning the compressors discussed by the commenter, we do not believe it is relevant that the compressors are needed because the separation facilities are located distant from the well sites. Such compressors meet the definition of "compressor station" as proposed and would be subject to the fugitive emissions monitoring provisions of §60.5397a.

We disagree with the commenter that the definition of "well site" should not include tank batteries located away from the well site. We do not believe that the distance the tank battery is located from the well site is a determining factor for whether fugitive emissions monitoring should be required for storage vessels. If the storage vessels are "collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries)" as stated in the definition of "well site," then they are subject to applicable requirements just as would those storage vessels in the immediate vicinity of the well site. Additionally, we believe that excluding tank batteries not located at the well site could incentivize some owners or operators to place new tank batteries further away from well sites to make use of such an exemption. Also see section VI.F.1.j of the preamble to the rule for further discussion.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 4

Comment: EPA Must Clarify That Midstream Assets Are Excluded From the Definition of Well Site for Purposes of Fugitive Emissions Monitoring

In the final rule, EPA must clearly exclude co-located midstream assets from the fugitive emissions monitoring program for well sites. GPA is concerned that, as proposed, EPA's broad definition of "well site" and "fugitive emissions component" could be interpreted to subject midstream assets to fugitive emissions monitoring requirements simply because they are located in geographic proximity to a production facility. Such an approach is inconsistent both with the way that the oil and natural gas sector operates and with the CAA. To avoid unnecessary and unreasonable burdens on midstream operators, GPA urges EPA to make appropriate clarifications and changes to the proposed rule so that co-located midstream assets are not inadvertently included in fugitive emissions monitoring requirements designed for oil and natural gas producers.

Upstream natural gas production and midstream gas gathering and processing are fully distinct and sequential portions of the natural gas sector supply chain. After natural gas is extracted from the earth by producers, the natural gas is typically transferred to separate and legally distinct midstream companies that own and operate gas gathering lines and processing plants. Because they are separate and legally distinct entities, agreements between upstream producers and midstream operators contain precise transfer of custody agreements that define when and where natural gas extracted by producers enters into the custody and control of the midstream operator. In many cases, this occurs immediately before the natural gas enters into a metering run. In a given gathering area, a midstream company could have hundreds of metering runs located on third-party producers' well pads spread across a wide geographic area.

Because the transfer of custody location serves as the dividing line between the gas production and gas gathering sectors, it is commonly found in close proximity to the well site. In fact, in many instances, the transfer of custody location may be found within the well site's footprint. As a result, there are many cases where a midstream operator may have equipment that is co-located at the well site. In some cases, this may be a matter of convenience based on the configuration of the production and midstream assets. In other cases, it may be a matter of necessity due to the amount of land available for oil and gas development (e.g., surface disturbances are minimized to reduce impact on wildlife). In either case, a midstream company may own, operate, or lease equipment that is located within the physical footprint of a well site. However, even when equipment is co-located at a well site, the producer has no control over the midstream assets and the midstream operator has no control over the production assets.

Despite this important distinction between production and midstream assets, the proposed definitions appear to mistakenly group production and midstream equipment together when co-located at a single well site, even though they are owned and operated by distinct entities. Thus, EPA's proposed regulations do not clearly and sufficiently address the issue of co-located midstream assets. For purposes of EPA's proposed fugitive emissions monitoring requirements, EPA broadly defines "the collection of fugitive emissions components at a well site" as "an affected facility." Proposed 40 C.F.R. § 60.5365a(i). In turn, EPA includes broad definitions for both fugitive emissions components and well site. Fugitive emissions components are defined as:

any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

Id. § 60.5430a. A well site is defined as:

one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at § 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

Id. Neither of these definitions reflects the fact that, due to convenience or necessity, certain distinct assets that are owned or operated by midstream companies may be co-located within the physical footprint of a well site. Thus, because some of their equipment also arguably would meet this broad definition of fugitive emissions components, co-located midstream assets could be construed as subject to proposed well site LDAR requirements under these broad proposed definitions.

Including co-located midstream assets in the fugitive emissions monitoring program for well sites is inappropriate for a number of reasons. First, as described above, equipment owned, operated, or leased by midstream operators is legally distinct from equipment owned, operated, or leased by upstream producers. Given their separate and distinct legal status EPA must establish separate requirements for upstream and midstream equipment. It is arbitrary and capricious to include some midstream assets in the fugitive emissions monitoring program simply because they are co-located within the footprint of a well pad site while excluding other midstream equipment that is located on a separate parcel of land.

Second, with respect to modifications, an LDAR program that does not distinguish between production and midstream assets raises serious concerns for GPA's midstream members. Under EPA's proposal, existing midstream equipment that is co-located at a well site could become subject to Subpart OOOOa if an upstream producer constructed a new well, refractured an existing well, or undertook a number of other actions that could increase upstream emissions at the site. Under the proposal, such a modification by an upstream operator would trigger Subpart OOOOa fugitive emissions monitoring for both the upstream and midstream assets. It is patently unreasonable to subject a midstream operator to fugitive emissions monitoring requirements under Section 111(b) of the CAA when that operator did not take any action to modify its own equipment. This is particularly true because under most agreements, an upstream producer would not have any obligation to notify the midstream operator that a modification had occurred. Thus, given the short deadlines proposed by EPA for conducting initial fugitive emissions monitoring, a midstream operator could find itself in violation of the fugitive emissions monitoring requirements before receiving notice that the well site had been modified.

Furthermore, an upstream producer cannot satisfy the LDAR requirements for the entire well site because much of the co-located equipment is proprietary to the midstream operator and cannot be accessed by the producer. This is particularly true of metering runs which are used to establish the payments owed by producers to midstream operators. Allowing producers to survey and repair such equipment would create a conflict of interest that is avoided by prohibiting upstream producers from accessing such equipment. For these reasons, EPA should not include midstream assets within the scope of the upstream fugitive emissions monitoring program for well sites.

Third, EPA's proposal is inconsistent with the statutory limitations included in Section 111 of the CAA. Section 111 defines a stationary source as "any building, structure, facility, or installation which emits or may emit any air pollutant." 42 U.S.C. § 7411(a)(3). Courts have repeatedly rejected EPA's attempts to expand the scope of the term stationary source. For example, in Asarco v. EPA, 578 F.2d 319 (D.C. Cir. 1978), the court rejected EPA's attempt to apply a "bubble concept" that allowed it to combine emissions from several sources in the same facility. The court held that "[t]he regulations plainly indicate that EPA has attempted to change the basic unit to which NSPSs apply from a single building, structure, facility, or installation—the unit prescribed by statute—to a combination of such units. The agency has no discretion to rewrite the statue in this fashion." Id. at 326-27. Similarly, in Alabama Power Co. v. Costle, 636 F.2d 323, 397 (D.C. Cir. 1979), the court confirmed that under "the limited scope afforded the term 'source' in section 111(a)(3), however, EPA cannot treat contiguous and commonly owned units as a single source unless they fit within the four permissible statutory terms [of building, structure, facility, or installation]." There the court explained that common ownership could provide a basis for aggregating some sources under the term facility or structure. Id. However, there is no basis to suggest that EPA can expand the term "facility" to include entirely separate sources that are part of different industry segments (upstream v. midstream) and owned and operated by legally distinct entities. It is fully unsettled and inappropriate to aggregate sources owned by different entities as a means of expanding the scope of the NSPS requirements. EPA offers no statutory basis for this implied expansion of its authority under Section 111.

GPA believes that EPA can resolve this problem and avoid imposing unlawful requirements on midstream operators simply due to their equipment being co-located at well sites by explicitly excluding those midstream assets from its fugitive emissions monitoring regulations for well sites. Colorado faced a similar challenge when developing its own fugitive emissions monitoring program. After consulting with industry members who raised these same concerns with the state, Colorado modified its proposed regulation and explicitly limited the scope of the fugitive emissions monitoring program at well sites to equipment that was owned, operated, or leased by the producer:

"Well production facilities" are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting).

5 Colo. Code Reg. 1001-9, Section XVII.A (2014). As a result of these changes, midstream operators in Colorado are only subject to fugitive emissions monitoring requirements if their own equipment triggers applicability requirements. They cannot become part of an affected facility based on the actions of unrelated, third-party producers.

EPA could exclude midstream assets from well site LDAR requirements by adopting the same approach as Colorado and limiting the well site LDAR program to sources that are owned, operated, or leased by producers. For example, EPA could revise Proposed 40 C.F.R. § 60.5365a(i) as follows:

Except as provided in 40 C.F.R. § 60.5365a(i)(1) through (i)(2), the collection of fugitive emissions components ***owned, operated or leased by the producer*** *at a well site, as defined in 40 C.F.R. § 60.5430a, is an affected facility.*

Such an approach has the advantage of well-understood property rights to determine the equipment at a well site that can be included in the LDAR program. As an alternative, EPA could adopt a process-based exclusion that focuses on the transfer of custody between the upstream producer and midstream operator. EPA already incorporates a "custody transfer" concept which is defined as:

the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

See Proposed Section 40 C.F.R. § 60.5430a; 80 Fed. Reg. at 56,694. This definition clearly distinguishes between gas processing plants and transmission lines. A similar definition could be applied to draw the line between upstream production and midstream gathering segments. To clarify that midstream equipment co-located at well sites are not subject to the well site LDAR requirements, EPA could revise Section 60.5365a(i) as follows:

Except as provided in § 60.5365a(i)(1) through (i)(2), the collection of fugitive emissions components at a well site, as defined in § 60.5430a, ***to the point of custody transfer****, is an affected facility.*

GPA believes that either of these approaches could effectively avoid regulating midstream assets from the upstream LDAR requirements for well sites simply because they are co-located at well sites.

Further, even if EPA wanted to regulate midstream assets located at well sites, it could not do so at this time due to a lack of costing data. EPA has an obligation under Section 111 to ensure that its regulations are cost-effective. See 42 U.S.C. § 7411(a)(1) (directing EPA to "tak[e] into account the cost of achieving such [emission] reduction" when establishing standards of performance under Section 111(b)). Here EPA has made no effort to identify the costs associated with LDAR monitoring at such midstream equipment or to determine whether such monitoring would be cost effective. Indeed, such an analysis is lacking in both EPA's proposed rule and in EPA's White Paper "Report of Oil and Natural Gas Sector Leaks" (April 2014). Without such an evaluation, EPA cannot satisfy the CAA's requirement to take into account the cost of LDAR monitoring for midstream assets located on well sites. Further, given the limited number of components associated with such equipment, it seems unlikely that EPA could demonstrate that such requirements are cost effective, since many of the costs are fixed and do not vary significantly with changes in component counts. Thus, until EPA completes the necessary cost analysis for midstream assets located as well sites and establishes that fugitive emissions monitoring surveys are cost effective, it cannot regulate such sources under Section 111(b).

Response: The collection of fugitive emission components at a well site, regardless of the owner or operator, is the affected facility and is subject to the fugitive emissions monitoring and repair program requirements specified in §60.5397a, including . The introductory text of §60.5365a states that "[y]ou are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification or reconstruction after September 18, 2015." Therefore the owner or operator is responsible for complying with the applicable standards. The commenter should be mindful, however, of the definition of "owner or operator" in §60.2 of the General Provisions which states that owner or operator means "any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part." We believe that the resolution for any leaking components identified during surveys can be managed by the operator through cooperative agreements with other potential owners at the site.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 108

Comment: EPA Must Exclude Co-Located Midstream Assets From Well Sites

In the final rule, EPA must clearly exclude co-located midstream assets from the fugitive emission monitoring program for well sites. As proposed, EPA's broad definition of "well site" and "fugitive emission component" could be interpreted to subject midstream assets to fugitive emission monitoring requirements simply because they are located in geographic proximity to a production facility. Such an approach is inconsistent both with the way that the oil and natural gas sector operates and with the CAA. Upstream natural gas production and midstream gas gathering and processing are fully distinct and sequential portions of the natural gas sector supply chain. Appropriate clarifications and changes to the proposed rule need to be addressed so that co-located midstream assets are not inadvertently included in fugitive emission monitoring requirements designed for well sites.

Including co-located midstream assets in the fugitive emissions monitoring program for well sites is inappropriate for a number of reasons. First, equipment owned, operated, or leased by midstream operators is legally distinct from equipment owned, operated, or leased by upstream producers. Given their separate and distinct legal status EPA must establish separate requirements for upstream and midstream equipment. It is arbitrary and capricious to include some midstream assets in the fugitive emissions monitoring program simply because they are co-located within the footprint of a well pad site while excluding other midstream equipment that is located on a separate parcel of land.

API believes that the recommended definition changes discussed above in section 27.2.5 will partially help alleviate this problem. However, API recommends that EPA should also limit well site requirements to the equipment owned or operator by the well operator. API notes that more detail on this issue is provided in comments submitted by the Gas Processors Association (GPA), along with recommended regulatory text.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 4.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 31

Comment: EPA Should Ensure LDAR Requirements Apply Comprehensively to Gathering Facilities.

Regarding the scope of facilities required to be monitored under EPA's proposal, we support EPA's inclusion of facilities in the upstream and midstream segments, including: (1) oil and natural gas well sites; (2) compressor stations in the gathering and boosting and transmission and storage segments; and (3) natural gas processing plants. We are concerned, however, that EPA's proposal could exempt some potentially high-emitting gathering facilities, and urge EPA to ensure that the final LDAR provisions of the rule seamlessly apply to major facilities throughout the gathering segment.

Comprehensive and rigorous LDAR requirements are particularly important for the gathering segment, which recent studies show to be one of the most significant sources of emissions in the oil and gas sector. According to a recent measurement-based study by Colorado State University researchers, facilities in the gathering segment nationwide are estimated to emit approximately 1.7 million metric tons of methane per year— about eight times the GHGI's estimated emissions from gathering systems. Infrared camera inspections at the gathering facilities found leaks at a substantial percentage of gas gathering facilities measured.

We also know from prior studies that a substantial share of emissions from these facilities is likely attributable to fugitive leaks and improperly functioning equipment that can be addressed through regular instrument-based LDAR.

EPA has proposed regulatory language that could have the unfortunate effect of exempting potentially high-emitting gathering facilities from the program. Under the proposed rule, LDAR requirements would apply to the "collection of fugitive emissions components" at both "well sites" and "compressor stations" in the transmission and gathering segments. 80 Fed. Reg. at 56,664 (proposed 40 C.F.R. § 60.5365a(i)-(j)). "Well sites" are defined to include "production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad," as well as "centralized tank batteries" that collect liquids from wells not located at an individual well site. *Id.* at 56,697 (Proposed 40 C.F.R. § 60.5430a). As a result of these definitions, the proposed LDAR requirements can be interpreted *not* to apply to certain gathering facilities—in particular, centralized gathering facilities that are not "directly associated" with a well pad and that are not co-located with compressor stations or tank batteries that are expressly covered by the proposed rule.

This potential gap in coverage raises two concerns. First, recent field research indicates that there are some potentially high-emitting gathering facilities that are not associated with storage tanks or compressors. Specifically, a February 2015 study by Colorado State University examined methane emissions from 114 randomly selected gathering facilities in multiple states. Of the facilities sampled, six consisted of sites that contained neither on-site compression nor storage vessels and would therefore potentially be excluded from EPA's proposed affected source definitions for LDAR. These six facilities included dehydration and treatment equipment, and recorded throughput as high as 650 million standard cubic feet per day (MMSCF/d). The emission rates from these six facilities averaged 0.65 percent of throughput (with a maximum emission rate of over 2 percent). This is comparable to or higher than the emission rates for many of the gathering compressor stations examined in the study. Moreover, the average emissions rate from these six facilities was 11.7 kg/hr – slightly higher than the average emission rate for the (larger) number of gathering compressor stations measured, which was 11.3 kg/hr. Second, this gap in coverage could inadvertently incentivize owners of oil and gas facilities to deliberately develop gathering facilities in such a way as to avoid becoming affected sources. If this were to occur, a growing number of gathering facilities could become exempt from the LDAR requirements.

In order to ensure comprehensive coverage of LDAR requirements in the gathering segment and avoid such perverse incentives, we urge EPA to clarify in the final rule that all centralized gathering facilities are subject to LDAR requirements. This could be accomplished by amending the proposed definition of "well site" to explicitly include centralized gathering facilities that are associated with one or more well pads and that contain fugitive emissions components as defined in proposed 40 C.F.R. § 60.5430a.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 4.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 18

Comment: EPA Should Consider Limiting Fugitive Emission Control Requirements to Gross Emitters

QEP welcomes the opportunity to comment on and further explore the concept with EPA of limiting the proposed fugitive emissions monitoring program to "gross emitters" or the minority of components that contribute a majority of fugitive methane and VOC emissions. 80 Fed. Reg. at 56637. QEP believes EPA can limit its fugitive emissions control program to certain fugitive emission components that have the highest potential leak rate and maintain the same environmental benefit associated with a program that includes the full universe of components.

To target "gross emitters," QEP recommends EPA focus on (1) the most common sources of leaks, such as valves, open-ended lines, and pumps, or "high motivated operation equipment" and (2) only those components with the potential to operate at or above sales line pressure. Components operating at these higher pressures are more likely to emit greater amounts of fugitive emissions should a leak occur. QEP suggests EPA consider these ideas before finalizing the fugitive emission control program in NSPS OOOOa.

Response: We disagree with the commenter that the final rule should focus on "gross emitters". Even though some components have lower emissions factors in comparison to other components, the large number of these lower emission components makes up a large portion of emissions. As an example, connectors have an average fugitive methane rate of 0.0002 kilograms per hour per component, but the large number of them results in a fugitive emission rate of 0.7 tons per year at a natural gas production well site. We believe these fugitive emissions are considerable and believe that a frequent monitoring program will significantly reduce these emissions.

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 29a

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 28a

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 29a

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 29a

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 29a

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 30

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number 24

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 64, 65, 66

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 24

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 21

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 21

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 8e

Comment: Many larger leaks can be discovered without using special equipment through visual, auditory, or olfactory inspection. These simple and effective detection methods allow the industry to address the large leaks with which EPA should be most concerned about, without imposing the same burdens as the Rules. Unlike the industry's methods of detecting large leaks, the Rules set an unreasonably low threshold for the types of leaks that must be found and fixed.

The Methane NSPS defines a fugitive emission as anything that can be seen using OGI technology, and mandates that all sources of those emissions must be repaired within 15 days.

OGI cameras are able to detect leaks at levels that are not environmentally meaningful, and do not provide the operator with information about the quantity of emissions. For example, a release of 1000 mcf of natural gas in a given time can read the same on the camera as a release of 10 mcf. Rather than encouraging operators to prioritize large leaks, the Rules do not distinguish between these larger and smaller leaks and require operators to address all visible leaks in exactly the same way and on the same timeline. The Rules also require the exact same reporting and recordkeeping requirements on leaks of all sizes. Indeed, the only distinction that the Rules make is based on the number of leaking components, rather than the quantity of emissions from the leaks. By setting the frequency of surveys based on the percentage of leaking components, operators are incentivized to correct multiple small leaks before fixing one large leak.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18. We also note that in the final rule we are allowing the use of Method 21 to detect leaks in addition to the use of OGI. We believe having this option will alleviate most of the commenters concerns. See response to DCN EPA-HQ-OAR-21010-6240, Excerpt 2. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information on fixed frequencies for monitoring surveys.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 5

Comment: EPA's Proposed Leak Detection And Repair Program For Fugitive Emissions From Compressor Stations Should Protect Against Inadvertent Increases In Emissions And Allow The Use Of Accepted Leak Detection Methods.

EPA's proposed standard to reduce fugitive methane and VOC emissions from new and modified natural gas compressor stations would require an LDAR program that targets all sources of fugitive emissions, regardless of the size of the leak, and that would require repairs that, in some instances, would result in additional emissions and that could exceed the fugitive emissions being addressed.

Response: We have made changes to the repair requirements for leaks found during the monitoring survey that will prevent the emissions due to venting. We are finalizing 30 days for the repair of fugitive emissions sources and an additional 30 days for resurvey of the repaired fugitive emissions components. We also are finalizing revisions to the delay of repair requirements. If a repair cannot be made due to a technical infeasibility that would require a blowdown or shutdown of the compressor station, or would be unsafe to repair by exposing personnel to immediate danger, the repair can be delayed until the next scheduled or emergency blowdown or station shutdown or within 2 years of finding the fugitive source of emissions, whichever is earlier. We believe that the likelihood of an emergency blowdown or a compressor station shutdown occurring within six months of finding fugitive emissions from a component may be low; however, it would be feasible to repair the component within a two-year timeframe, since one of above described events is likely to occur within that two-year timeframe.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 55

Comment: Finally, EPA requests comment on whether fugitive emissions monitoring should be limited to "gross emitters." 80 Fed. Reg. 56,637. As we have commented in section B above, the occurrence of super-emitters / gross-emitters is not predictable. Such an approach is not workable. Comprehensive monitoring is required to ensure that when improper conditions occur, repairs are rapidly made to ensure that unnecessary and harmful emissions do not continue.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 34

Comment: The purpose of a DI&M program is to identify leak sources and mitigate methane emissions based on a prioritization process that assesses emissions potential from a particular source or component. EPA's Natural Gas STAR program, among other analyses, has demonstrated that a relatively small percentage of leaks contribute to the vast majority of emissions for natural gas operations—e.g., 95% of methane emissions from equipment leaks are from 20% of the leaks at compressor stations.

EPA inappropriately ignores the data resulting from the Natural Gas STAR program, Subpart W and other recent studies, and instead relies on data from the U.S. GHG Inventory ("GHGI") to estimate the contribution of methane from the natural gas transmission and storage segment. Such data does not provide either the best or most recent data available, and EPA should not rely exclusively on this data as the basis for establishing new requirements for the natural gas transmission and storage sector, particularly as it relates to fugitive emissions leak detection requirements. In fact, a recent study developed by Environmental Defense Fund ("EDF") and Colorado State University, and supported by members of the natural gas transmission and storage segment, including Kinder Morgan, indicate that the GHGI significantly overestimates the amount of emissions coming from the natural gas transmission and storage segment for sources other than uncombusted methane in engine/turbine exhaust and reciprocating compressor leaks. Similar overestimations by the GHGI were found in other recent and EDF-supported studies with respect to workovers and completions in the production segment; processing plants; and underground pipeline leaks in the distribution sector.

Specifically, in the natural gas transmission and storage sector, the non-compressor emissions make up approximately half of the GHGI for transmission facilities and one-sixth from storage facilities when the super-emitters are excluded. In the distribution sector, three large leaks contributed 50% of the total emissions measured during the study, (Lamb et al. 2015). Similarly, the evaluation of pneumatic controllers found that 20% of devices accounted for 96% of the methane emissions. In the production segment and with respect to unloading events without a plunger lift, 3% of the wells accounted for 50% of the emissions, (Allen et al. 2013), while, in the gathering segment, only 30% of facilities account for 80% of the total emissions. These studies and values cannot be overlooked and ignored as EPA proposes to do here. A focus on those specific components or equipment with the greatest chance of leaking and the most significant leaks will provide the same, if not better, benefits as a comprehensive leak detection program—with significantly reduced costs and burdens.

After similar operator experiences in Canada, in January 2007, the Canadian Association of Petroleum Producers ("CAPP") developed best management practices ("BMPs") for "Management of Fugitive Emission at Upstream Oil and Gas Facilities" to ensure fugitive emissions management programs are "targeting the sources that are most likely to have larger volume emissions and which would be more cost effective to address," understanding that only a small percentage of equipment components contribute to most emissions. The CAPP BMP provides operators flexibility in developing DI&M programs that are tailored to their specific facilities, allowing operators to focus on the gross emitters and limit frequency of inspection (annually). And in fact, in 2013, CAPP commissioned a study to measure the effectiveness of the DI&M programs and found that "overall, the emissions due to fugitive leaks have decreased by 75 percent since the implementation of DI&M programs."

In sum, a DI&M program leverages the characteristic of gross emitters through procedures that focus inspection and repair on larger leaks and avoid unnecessary inspection and repair to inconsequential leaks. The data collected from a DI&M program, along with subpart W data, would also provide insight into the program's performance, allowing adjustments to be made (e.g., focusing on more or fewer potential leak sources).

Response: We reviewed data from a number of different sources, including the documents referenced by the commenter. We believe the data from the GHG Inventory provides the best estimate of fugitive emissions from compressor stations. Regarding the DI&M program as described by the commenter, this program has significant deficiencies compared to the subpart OOOOa program as finalized. Specifically, the DI&M program "focuses on key leak sources within a facility that pose a higher probability of being gross emitters or super emitters." Thus the DI&M program would not survey components that were not deemed capable of being a super emitter. We believe that this approach could allow for a large number of components to develop leaks and go undetected, leading to excess emissions that would otherwise be detected and repaired under the subpart OOOOa program. Additionally, the DI&M program as defined by the commenter calls for annual surveys. The subpart OOOOa program as finalized requires semiannual surveys of well sites and quarterly surveys of compressor stations. We believe these more frequent surveys will lead to greater methane and VOC emission reductions than the annual surveys of the DI&M program. For these reasons, we do not consider the DI&M program to be equivalent to the subpart OOOOa program and reject the commenter's request to allow compliance with the DI&M program in lieu of the subpart OOOOa requirements.

Additionally, we note that we have added a procedure at §60.5398a of the final rule for owners or operators of affected facilities to apply to the Administrator for a determination of whether an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §60.5397a. Such an alternate means may include corporate fugitive emissions monitoring programs that deviate from the requirements of §60.5397a. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 12

Comment: In addition, providing operators flexibility in developing LDAR programs similar to directed inspection and maintenance (DI&M) programs tailored to their specific facilities or groups of facilities provides significantly greater fugitive emissions benefits at a much lower cost than the type of rigid and inflexible program being proposed nationwide by EPA (or being implemented in Colorado). *See Management of Fugitive Emissions at Upstream Oil and Gas Facilities*, Canadian Association of Petroleum Producers at 1 (In the upstream oil and gas sector "[o]nly a small percentage of the equipment components have any measurable leakage, and of those only a small percentage contributes to most of the emissions. Thus, the control of fugitive emissions is a matter of minimizing the potential for big leaks and providing early detection and repair.") In this respect, the Alliance strongly supports a flexible approach and believes that, at most, EPA should be focusing its LDAR program on high or "gross" emitting components/facilities. *See* 80 Fed. Reg. at 56,637 ("[W]e solicit comment on whether the fugitive emissions monitoring program should be limited to 'gross emitters.'") Allowing operators to focus monitoring efforts on the components that are most likely to leak, and those that are most likely to have the highest leak rates, maximizes both the emissions reductions and cost-efficiencies of an LDAR program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 34 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 25

Comment: EPA is soliciting comment on whether its LDAR program should be limited to gross emitters. We understand gross emitter as a term used to describe data that indicates a majority of fugitive methane and VOC emissions come from a select minority of components. We strongly support focusing a LDAR program on gross emitters, as doing so provides the most cost-effective, environmentally beneficial approach.

The Alliance believes the rule can, and should, limit its fugitive emissions control program to certain high or "gross" emitting components. Components operating at these higher pressures are more likely to emit greater amounts of fugitive emissions should a leak occur. For example, to target "gross emitters," the proposed rule can focus on: (1) the most common sources of leaks, such as valves, open-ended lines, and pumps, or "high motivated operation equipment"; and (2) only those components with the potential to operate at or above sales line pressure. Focusing on gross or high emitters will result in the same environmental benefits, and still address the components of primary concern

EPA has successfully used this flexible approach elsewhere, including in its DI&M program for Natural Gas STAR. This allows operators to maximize the cost effectiveness of their LDAR programs by focusing the most resources on quickly identifying and addressing the large leaks. A program that fails to recognize the importance of prioritizing the larger leaks will, by definition, not be the most cost-effective regulatory approach (if it is cost-effective at all). Operators will spend time and resources tracking down very small leaks, rather than identifying and correcting the large leaks as quickly and efficiently as possible.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 34.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 16

Comment: Providing operators flexibility in developing LDAR programs similar to DI&M programs tailored to their specific facilities or groups of facilities (developed for years under the Natural Gas STAR Program) provides significantly greater fugitive emissions benefits at a much lower cost than the type of rigid and inflexible program being proposed nationwide by EPA (or being implemented in Colorado). *See* "Management of Fugitive Emissions at Upstream Oil and Gas Facilities," Canadian Association of Petroleum Producers at 1 (In the upstream oil and gas sector "[o]nly a small percentage of the equipment components have any measurable leakage, and of those only a small percentage contributes to most of the emissions. Thus, the control of fugitive emissions is a matter of minimizing the potential for big leaks and providing early detection and repair.") In this respect, MarkWest strongly supports a flexible approach and believes that, at most, EPA should be focusing its LDAR program on high or "gross" emitting components/facilities. *See* 80 *Fed. Reg.* at 56,637 ("[W]e solicit comment on whether the fugitive emissions monitoring program should be limited to 'gross emitters.'"). Allowing operators to focus monitoring efforts on the components that are most likely to leak, and those that are most likely to have the highest leak rates, maximizes both the emissions reductions and cost-efficiencies of an LDAR program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 34.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 25

Comment: LDAR should be limited to gross emitters

EPA is soliciting comment on whether its LDAR program should be limited to gross emitters. We understand gross emitter as a term used to describe data that indicates a majority of fugitive methane and VOC emissions come from a select minority of components. We strongly support focusing a LDAR program on gross emitters, as doing so provides the most cost-effective, environmentally beneficial approach *(see* discussion above in Section II.A.).

EPA has successfully used this flexible approach elsewhere, including in its DI&M program for Natural Gas STAR. This allows operators to maximize the cost effectiveness of their LDAR programs by focusing the most resources on quickly identifying and addressing the large leaks. A program that fails to recognize the importance of prioritizing the larger leaks will, by definition, not be the most cost-effective regulatory approach (if its cost-effective at all). Operators will spend time and resources tracking down very small leaks, rather than identifying and correcting the large leaks as quickly and efficiently as possible.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 34.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 36

Comment: EPA acknowledges that a broad fugitive emissions monitoring program could prove problematic in terms of implementation and cost and specifically solicited comment on whether the program should be limited to "gross emitters":

> Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources. Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of

> components (e.g., gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to "gross emitters.

TXOGA agrees with EPA that the fugitive emissions program should be limited to "gross emitters." A broad fugitive emissions monitoring program will be extremely costly and yield limited environmental benefit and does not represent the "best balance of economic, environmental, and energy considerations" required under the BSER analysis. EPA is also correct that a small number of components, specifically compressors and flashing tanks, are responsible for the majority of fugitive leaks.

EPA should provide for a Directed Inspection and Maintenance (DI&M) program in lieu of a Leak Detection and Repair (LDAR) program as an efficient and cost effective means of mitigating leaks from gross emitters. The DI&M approach, which has long been voluntarily applied by industry and is well documented through EPA's Natural Gas STAR program, differs from LDAR in that the DI&M program approach efficiently and effectively facilitates identification of components that are the highest emitters. By contrast, LDAR requires leak detection surveys of each individual component—a less efficient approach to target gross emitters.

An effective DI&M approach could include screening a site containing equipment that previous experience indicates has a higher probability of leaking with OGI from the site perimeter, not more than 100 feet from fugitive emissions components; identification of components observed by OGI to be leaking ("fugitive emissions"); repair of component or components within 30 days of discovery; and verification of repair with OGI or soap bubbles within 30 days following repair.

Accordingly, TXOGA supports limiting the fugitive emissions program to "gross emitters."

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 34 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 124

Comment: Fugitive Program For Gross Emitters

On page 56637 of the preamble, EPA indicated that commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, EPA solicited comment on whether the fugitive emissions monitoring program should be limited to "gross emitters".

As EPA acknowledges, a growing body of research indicates a skewed emissions distribution for fugitive emission sources where a small number of sources are responsible for a high percentage of emissions. The fugitive emission monitoring program under OOOOa should be targeted towards identifying and correcting these high emitting sources which results in the greatest cost-effective reductions, and produces significant reductions in emissions more quickly. As indicated in Section 27.3.9, API data on the leaks identified from recurring LDAR surveys indicates that annual LDAR is sufficient for identifying and correcting the relatively few fugitive sources with very high emission rates.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18.

Commenter Name: J. Jared Snyder
Commenter Affiliation: New York State Department of Environmental Conservation.
Document Control Number: EPA-HQ-OAR-2010-0505-6894
Comment Excerpt Number: 6

Comment: It is important for EPA to consider the idea of "gross emitters" with respect to emissions from oil and natural gas sources. While assumptions and available data are often used to quantify area source emissions, the DEC recognizes a need for further data in this field. Recent studies have shown that a significant portion of actual emissions may be the result of a small number of malfunctioning components. In the case of pneumatic controllers, 19% of those analyzed (377) accounted for 95% of methane emissions. Another example is that of gathering facilities, which collectively gather natural gas from production wells, remove the impurities and deliver it to the pipeline. The study results show that 30% of gathering facilities contribute 80% of the total emissions. These studies support the need to effectively regulate "gross emitters" and the DEC believes that by implementing the NSPS alongside State rules consistent with the CTG recommendation, emissions from these sources may be limited in nonattainment areas. EPA should also evaluate whether other regulatory authority, including Clean Air Act section 111(d), should be utilized to address methane emissions from existing "gross emitters," regardless of where they are located.

EPA requested comments on whether the fugitive emissions monitoring program should be limited to "gross emitters." The DEC recommends that the monitoring program not be limited to "gross emitters." By limiting the program in this manner, newly developed "gross emitters" may be allowed to emit longer because of the lack of monitoring. To the extent that some aspects of distribution systems are considered "gross emitters", local distribution companies should be allowed to propose alternatives for reducing emissions that limit ratepayer impacts. In some instances, a repair of a component may be less costly than replacement, for example, and so latitude in considering best-cost options should be allowed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18.

Commenter Name: Henri Azibert, Technical Director
Commenter Affiliation: Fluid Sealing Association (FSA)
Document Control Number: EPA-HQ-OAR-2010-0505-6754
Comment Excerpt Number: 7

Comment: Fugitive emissions are what the FSA members' products are specifically designed to address. There are several technologies to detect emission levels. Its members are not experts in assessing the detection level of all monitoring equipment. The members do have considerable experience with the EPA Method 21, and they believe that it is an accurate method to determine leakage levels, especially in the lower range of what is reasonably achievable control technology. This method has been adopted by industry standards (API and ISO) to validate the performance of emission sealing products, and has been extensively used in existing LDAR programs. Even though a single source of low level of emission sources may not be as significant as a large source, the extremely high number of potential sources makes the cumulative leakage notable. For this reason we do not believe that the fugitive emission monitoring program should be limited to "gross emitters." (Request for comment on page 253).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18.

Commenter Name: Alan Krupnick, Jan Mares and Clayton Munnings
Commenter Affiliation: Resources for the Future
Document Control Number: EPA-HQ-OAR-2010-0505-6918
Comment Excerpt Number: 2

Comment: The proposed rule should also be able to accommodate new information given our rapidly changing understanding of the sources of methane emissions. Given the now widely held belief that just a few sources are responsible for the lion's share of emissions at any one point in time, EPA should consider how it or the industry can best identify high emitters and then subject them to more stringent monitoring and enforcement than other sources. At the same time, we are concerned about the potentially high monitoring costs implied by the rule for sources that are emitting at very low rates which means EPA should consider lowering monitoring requirements for certain low emitting sources while acknowledging that super emitters can significantly change over time, such that emissions can be a moving target. This raises a fundamental and difficult question of how to appropriately pair the potential for emissions with monitoring requirements for particular categories of equipment. We recommend that the EPA consider establishing an ongoing process for adapting monitoring requirements for particular equipment categories over time based on updated information on the sources of methane emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)

Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 14

Comment: We urge EPA to replace its proposed fugitive emissions program with a more realistic and workable approach that properly takes into account the characteristics of compressor stations in the oil and gas industry. A report included in the docket of this rulemaking summarizes the sort of approach that should be adopted by EPA:

> The [upstream oil and gas] industry is characterized by many small widely dispersed facilities rather than a few large facilities so it is appropriate to apply a directed approach that targets the sources most practicable to control, components most likely to result in big leaks. At each target facility, efforts should be focused on the areas most likely to offer significant, cost-effective control opportunities (e.g., on specific component types and service applications).

That approach is embodied in the program that TPA recommends in place of EPA's current proposal. TPA's recommended program for fugitive emissions would be based on initial site screening, which would be aimed at identifying actual emission points - and especially so called "super-emitters," *i.e.,* the handful of emission sources that have been found to account for a great majority of methane emissions in the oil and gas industry. Various reports, including the recent EDF-sponsored studies focusing on methane emissions across the natural gas supply chain, have confirmed the presence of super-emitters. A site-screening model program would identify actual emission points, including proportionately large emitters, and thus would allow EPA to keep the regulatory focus where it belongs and would only impose find-and-fix requirements on those "problem" sources that were identified through site screening. This would ensure that company efforts and regulatory resources were well spent through identification and repair of those sources that are responsible for the majority of the emissions that EPA seeks to minimize. It would have the concomitant benefit of minimizing or eliminating burdens on the remainder of the sources that emit insignificant levels of methane emissions and that therefore should not be subject to the sort of extensive program requirements currently being proposed by EPA. The substantial time and effort that would be required to comply with the proposed Subpart OOOOa fugitives program should not have to be spent monitoring components that emit insignificant amounts of methane.

The basic outline of such a site-screening approach is as follows:

Subpart OOOOa Compressor Station Fugitive Emissions Monitoring Program Using Site Screening

Site Screening Fugitive Monitoring: Tier I

- Site screen using OGI camera:
  - Monitor from four screening locations that provide monitoring from each directional perimeter of the facility. Each monitoring location should be no more than 100 feet from the nearest site components.

- A leak is any visible (hydrocarbon) emission observed on the camera that is not designed to leak as part of intended function or process.
- If no visible emissions, monitoring is complete.
- If visible emissions are present during monitoring, proceed to Tier II.

Tier II

- Locate and identify the leaking component/components:
  - Repair component/components within 30 days.
  - Verify repair with OGI within 30 days after repair *(i.e.,* a second 30-day period).

Frequency:

- First monitoring event within 180 days of start-up.
- Annually thereafter. Once each calendar year, not to exceed one year between monitoring events.

Monitoring Plan:

- Corporate plan only. No site plans.
- List of facilities subject to monitoring and the date they became subject
- List of certified OGI operators.
- Copies of the OGI operators' certification, including an outline of the training program that was utilized for certification.

Recordkeeping:

- Keep OGI recording of each monitoring event (including repair events) for 5 years. Each monitoring event should be time, date, and location stamped.
- Records can be kept off site as long as they are accessible electronically.

Reporting:

- No reporting.
- Methane emission data is already reported through Subpart W.

Exemption for Site Fugitive Monitoring:

- Compressor Stations with less than 1000 HP are exempt from the site fugitive monitoring requirements.

Delays:

- Provisions for delay where repair would be unsafe or otherwise inappropriate *(see proposed 40 CFR § 60.5397a(j)(l)) would apply.*

This simplified site-screening approach would focus on the subset of industry sources that that account for the majority of methane emissions. As such it would provide for greater efficiency in the monitoring process, because targeting the highest emitting sources will result in achieving the greatest reductions in emissions at the lowest cost per ton. We think this is a sound approach and that the rules should be revised lo concentrate on reducing emissions from a subset of sources that account for the majority of oil and natural gas sector fugitive emissions - identified by our proposed site-screening approach.

Moreover, the site-screening approach is further justified by the fact that new facilities by definition have new equipment that is less prone to leak. This fact greatly reduces the need for industry-wide component-specific monitoring at all sources subject to NSPS - *i.e.,* sources that are new or that have been newly modified or reconstructed. New facilities use new equipment with the latest technological advances, and they go through a shake-down and commissioning process that is designed to find-and-fix safety and process issues, including leaks. Accordingly, it is appropriate for EPA to substitute TPA's site-screening program for the agency's "every site" monitoring program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 34

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number 29

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 26

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 27

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 27

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 28

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 27

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 59

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 22a

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 8a

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 22a

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 19a

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 19a

Comment: The Rules also focus far too many resources on correcting minor leaks. Instead of concentrating on large leaks, which are more meaningful contributors to emissions, the Rules would force companies to devote vast amounts of resources to continuously checking for small leaks that have a negligible impact on emissions. Large leaks are bad for business, and the industry has already found cost-effective ways to catch those leaks, including through voluntary programs such as the Natural Gas STAR Methane Challenge Program. As previously noted, methane emissions from the E&P sector have fallen in recent years despite the tremendous increases in oil and gas production. These declining emissions indicate that the industry has found effective ways to address the sources of these emissions. EPA should continue to encourage these industry-generated improvements, which would be hindered by the fugitive monitoring requirements found in the Rules.

Response: We agree that voluntary programs have reduced fugitive emissions from well sites. However, we believe the implementation of a semiannual monitoring program will reduce significant emissions of both methane and VOC from these sites.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 14

Comment: As previously noted, methane emissions from the oil and gas sector have fallen in recent years despite the tremendous increases in oil and gas production. These declining emissions indicate that the industry has found ways to address the sources of these emissions. Large leaks are bad for business, and the industry has already found cost-effective ways to catch those leaks. For example, many larger leaks can be discovered without using special equipment through visual, auditory, or olfactory inspection. These simple and effective detection methods allow operators to address the large leaks with which EPA should be most concerned, without imposing the burdens proposed in NSPS Subpart OOOOa.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 29.

Commenter Name: Mark A. Litwin
Commenter Affiliation: Paiute Pipeline Company
Document Control Number: EPA-HQ-OAR-2010-0505-6814
Comment Excerpt Number: 6

Comment: Paiute's compressor stations are remotely located, such that access is challenging. Paiute believes that instead of adopting a LDAR program that requires operators to detect and repair all leaks, regardless of leak size, within a specified time period, EPA should adopt a directed inspection and maintenance (DI&M) program approach which allows operators to focus on locating and repairing large leaks, and which includes common delay-of-repair provisions which would allow consideration of operational and scheduling constraints.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 34 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Shawn Bennett, Executive Vice President
Commenter Affiliation: Ohio Oil & Gas Association (OOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6921
Comment Excerpt Number: 8

Comment: EPA also requested comments on the LDAR program being limited to "gross emitters." The Association agrees with that approach since fugitive emissions can come from a small minority of components. In that manner, EPA can create a cost-effective LDAR program that effectively monitors "gross emitters" and exempts the vast majority of sites and equipment that would qualify as de minimis emission sources.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18.

Commenter Name: Kelly Guertin, Senior Environmental Engineer, Environmental Management and Resources
Commenter Affiliation: DTE Energy (DTE Gas Company)
Document Control Number: EPA-HQ-OAR-2010-0505-7052
Comment Excerpt Number: 5

Comment: DTE Energy agrees with AGA and INGAA that EPA’s proposed fugitive emissions program should focus on “gross emitters,” and should include a leak detection and repair program that takes into account real world operations, protects against inadvertent increases in emissions, and allows for the use of accepted leak detection methods.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 18.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 5

Comment: Although other provisions proposed in OOOOa apply to SWN, our most significant concerns relate to the fugitive emissions provisions applicable to our well sites and compressor sites. The proposed rules do not acknowledge the reductions achieved or will be achieved by companies implementing voluntary programs, including the EPA's own Methane Challenge program nor those achieved under state driven programs. The proposed rule does not provide flexibility for companies to utilize new or emerging monitoring and measurement technologies that may lower the cost of fugitive emissions controls at comparable or better results. Finally the proposed rule is overburdened with excessive administrative requirements that arguably have no or limited impact on fugitive emissions reductions.

SWN's comments are based on observations made in association with our voluntary fugitive emissions monitoring program (SWN LDAR Program) and are intended to support development of appropriate and "smart" fugitive emissions rules which we support. Our key recommendations to the fugitive component emissions proposed rules are outlined below. Additional detail comments and recommendations follow.

Rule applicability should have provisions for "low fugitive emissions sites" to be exempt from the rule.

- Well sites or compressor stations subject to a state regulatory driven fugitive emission control program should be exempt from the rule.
- Companies should have the option to submit corporate, company, area, or even site specific fugitive emissions monitoring plans (or LDAR plans) under a "Custom Plan" provision.
- Voluntary fugitive emissions monitoring plans being implement by companies participating in EPA Natural Gas STAR Methane Challenger under the ONE Future option should be recognized as an approved compliance alternative to the proposed "corporate-wide fugitive emissions monitoring plan" and the alternative "site-specific plan" requirements.
- Monitoring survey frequency should be an initial monitoring survey followed by an annual monitoring survey.
- Timelines to conduct the monitoring surveys should be at least 60-days.
- Provisions should be made for monitoring and measurement devices that can achieve comparable results as OGI and Method 21.
- Provisions should be made for the utilization of new and developing monitoring and measurement technology.
- Numerous provisions of the "corporate-wide fugitive emissions monitoring plan" and the "site specific plan" requirements should be removed from the rule.

Response: The EPA takes the commenter's concern that "the proposed rules do not acknowledge the reductions achieved" by voluntary programs to means that the commenter would like the rule to allow compliance with voluntary programs to be credited towards compliance with subpart OOOOa. We acknowledge and appreciate the efforts voluntarily undertaken by the commenter and others to implement fugitive emissions monitoring programs. Due to the complexity of these programs, demonstrating equivalency in emission reductions from one plan to another is not a simple matter. In response to this concern, which was expressed by several commenters, we have added §60.5398a to the final rule to provide a mechanism to apply to the Administrator for a determination on equivalency. See section VI.K of the preamble to the final rule for more detail regarding this issue.

The EPA agrees with the commenter on the type of monitoring plan submitted and has revised the final rule by replacing the proposed corporate-wide and site-specific monitoring plan requirements with a requirement for owners or operators to develop a corporate monitoring plan for company-defined areas that would cover the collection of fugitive emissions components at the compressor stations or well sites located within that company-defined area. See section VI.F.1.h and section VI.F.2.g of the preamble to the final rule for more detail regarding this issue.

Concerning monitoring frequency, see response to DCN EPA-HQ-OAR-2010-0505-6854, Excerpt 18.

See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Mike Cantrell, Chairman
Commenter Affiliation: National Stripper Well Association (NSWA)
Document Control Number: EPA-HQ-OAR-2010-0505-6758
Comment Excerpt Number: 9

Comment: The first area to examine is wellhead gas leaks. It should come as no surprise to EPA that leaks at the wellhead for producers are both a waste of valuable resources and a safety concern to oilfield employees. Operators make every effort to capture methane at the wellhead and ensure that the maximum volume of gas produced is captured. EPA, in this rulemaking, seems to think operators are either irresponsible by failing to capture the methane produced or carelessly, wasteful of the product they are producing. Both scenarios are false.

The process of leak detection, especially on low production wells, requires ongoing regular inspection by experts familiar with the equipment and the well site. In addition, producers know what level of production should be expected and are quick to investigate should leaks develop. A slew of companies have recently developed technology to make leak detection and abatement easier; however, the exorbitant costs of most of these technologies are frequently beyond the financial reach of small producers. Should EPA move forward with provisions in the rule that mandate these technologies be used with no consideration for the volume of gas produced at the wellhead, the results could be devastating. Instead, EPA should instead consider solely focusing requirements at wells that have significant production volumes, and as a result, potentially significant wellhead emissions.

Response: In the comments on the proposed rule, we did not receive additional data on equipment or component counts for low production wells. However, we did receive information stating that low production wells have the same equipment and component counts as a non-low production well site. This indicates that the potential emissions from low production well sites could be similar to that of non-low production well sites. We also believe that this type of well may be developed for leasing purposes but are typically unmanned and not visited as often as other well sites which would allow fugitive emissions to go undetected.

We also did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable and are including both types of wells in the fugitive emissions monitoring requirements in the final rule.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 16

Comment: Number two: While it -- while it is definitely appropriate to find all methane and VOC leaks, large leaks may occur at gas wells and operating sites. These super-emitters, as some people call them, release many times the quantity of future emissions anticipated from more typical small leaks.

These larger leaks are most impactful to the environment, and they result in the loss of revenue for the operators and the lessening of the resource of the operators in terms of their longevity.

It is therefore recommended that more rapid --more regular, rapid, and cost-effective monitoring is carried out for at least the larger leaks to be considered for the proposed regulations.

Response: We agree that limiting the number of gross emitters is an important step to reducing GHG emissions; however the only way that this can be accomplished is through periodic monitoring of these sites. We have included semiannual monitoring of well sites, which we believe will limit these fugitive GHG emissions.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 38

Comment: Fugitive emission monitoring programs need to go beyond "gross emitters." The EPA needs to be serious about potent methane and harmful VOC emissions. Well sites are not only near our homes and schools emitting harmful VOCs but also, methane is a serious problem 84 times more powerful than carbon dioxide in the first 20 years after its release. Additionally, harmful VOCs continue to increase within our regional air creating more opportunities for families and students to be exposed to cancer causing chemicals within their basic daily activities.

Response: We agree with the commenter and are now requiring semiannual fugitive emission monitoring for all well sites with the exception of well sites that only contain well heads.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 25

Comment: USEPA solicits comment on whether the fugitive emissions monitoring program should be limited to "gross emitters" as is consistent with trends identified by analyzing data from existing LDAR programs. Antero supports limiting the fugitive emissions monitoring program to a set of equipment that is known in the industry to be the source of the majority of fugitive emissions under normal operating conditions. There may be several fugitive emissions components associated with the equipment at a well site; however, only a small number leak. Therefore, Antero objects to the term "gross emitter" and would prefer the term "primary component emitter." The definition of "primary component emitter" should focus on equipment type.

Response: We are unable to determine which sites may be "gross emitters" and therefore have applied the fugitive emission requirements to all well sites with the exception of well sites that only contain well heads.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.

Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 105

Comment: These large emissions are due both to smaller sources that are collectively significant and to disproportionately unusual, but very large leaks commonly referred to as emitting "super-emitters." Many studies have demonstrated that there is a highly skewed distribution of leaks. The concentration of emissions within a small proportion of sources has been observed both among groups of components within a site and among groups of entire facilities. EPA's White Paper on Fugitive Emissions generally describes this type of distribution, with the majority of emissions coming from a minority of components and a minority of sites. Both the City of Fort Worth Natural Gas Air Quality Study and Allen, *et al.* (2013) provide extensive, site-wide emissions data that confirm the presence of super-emitters. In these studies, the highest 20 percent of emitting sites account for 60–80 percent of total emissions from all sites; the lowest 50 percent of sites account for only 3–10 percent of total emissions. Figure 1 below presents site-wide emissions for natural gas production facilities from both of these studies. Emission rate distributions from different source types are plotted as percent of sites in ascending order of emission rate versus percent of total emissions from sites at or below that rank. For example, the lowest emitting 50% of well pads contribute 1% of total emissions from measured sites, while the highest emitting 10% contribute 69% of total emissions. As is illustrated, all the studies represented in the figure observe roughly the same trend across all sectors of the value chain.

Figure 1 Distribution of Site-Wide Emissions at Natural Gas Production Sites

Equally important, studies have found that these super emitters—and, indeed, leaks in general—are at present largely unpredictable and may shift over time. In particular, the Barnett coordinated campaign mentioned above found that abnormal operating conditions, such as improperly functioning equipment could occur at different points in time across facilities. As a result, Zavala-Araiza, et al. reported that inspections need "to be conducted on an ongoing basis" and "across the entire population of production sites."

These results suggest that an effective emission reduction strategy must include frequent leak surveys to identify the highest emitting sites and address sources at those sites. Ultimately, the existence of super-emitters underscores that a comprehensive policy to address emissions is critical—one that focuses on detection and remediation of leaking sources using approaches that are well-adapted to finding the highest-emitting sources and sites.

Response: We agree with the commenter that fugitive emissions from well sites are largely unpredictable and may shift over time, and that the only effective emission reduction strategy is to require routine fugitive monitoring to address these emissions.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 13

Comment: Fugitive emissions from compressor sites are a relatively small portion of total emissions from a compressor station. When fugitive emissions are an issue, they tend to be from a small number of large leaks at specific facilities, rather than a large number of small leaks at many stations. As a result, any regulatory efforts from EPA should be focused on finding and repairing those few major leaks. For example, a study released earlier this year by Colorado State University demonstrates that a small number of leaks, called "super emitters" account for a large percentage of emissions from leaks at compressor stations. The study found that the highest emitting 10% of sites (including two super emitters) contributed 50% of the aggregate methane emissions, while the lowest emitting 50% of sites contributed less than 10% of the aggregate emissions. The report noted that similar results had been found in upstream natural gas operations, where 10% of the gas wells contributed nearly 70% of the emissions from 250 Texas gas wells measured in another study. EPA can already identify who these "super emitters" are through its GHG Reporting Rules. EPA can, therefore, better reach its goal of limiting methane emissions from the transportation and storage segment by targeting these isolated cases of major emissions through encouraging voluntary reduction programs, rather than instituting an expensive and burdensome industry-wide program to look for small leaks.

Response: We greatly appreciate the voluntary measures undertaken by many stakeholders in the oil and natural gas production industry. We believe that we have shaped the final rule such that these stakeholders will be able to more readily implement the standards given their existing programs. However, the best approach for finding these "super emitters" is through a frequent monitoring program. Not only will the frequent monitoring program find these "super emitters", it will also prevent other smaller leaks from becoming "super emitters".

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 6

Comment: EPA's Standards of Performance for Affected Facilities in the Segment Should Focus on Gross Emitters.

EPA erred by focusing on the percentage of leaking components and equipment pieces at compressor stations rather than the volume of leaks.

EPA requests comment on whether the fugitive emissions standard for compressor station "affected facilities" should focus on larger leaks, which EPA refers to as gross emitters. There is scientific evidence to support focusing on gross emitters, and INGAA agrees that the standard should focus on large leaks from gross emitters.

There is scientific evidence that the vast majority of leaks, over 80 percent, in the T&S sector come from a small number of sources called "gross emitters." The Environmental Defense Fund (EDF), industry and Colorado State University (CSU) published a collaborative study documenting that a small number of leaks, termed in that study as "super emitters," account for a large percentage of emissions from leaks. These leaks are also called either "gross emitters" or "long tail emitters." The CSU study concludes that "the highest emitting 10 percent of sites (including two super emitters) contributed 50 percent of the aggregate methane emissions, while the lowest emitting 50 percent of sites contributed less than 10 percent of the aggregate emissions." In addition, EPA's Natural Gas STAR program, among other analyses, has demonstrated that a relatively small percentage of leaks contribute to the vast majority of emissions for natural gas operations, e.g., 80 to 90 percent of methane emissions from equipment leaks are from 20 percent of the leaks at compressor stations. Moreover, as discussed below, EPA's Subpart W monitoring data also supports the conclusion that a small category of equipment account for a majority of the fugitive emissions from a compressor station.

INGAA supports EPA's goal of reducing methane emissions from the T&S sector. EPA can meet its goal by permitting natural gas pipeline operators to focus on "gross emitters." INGAA strongly supports a programmatic approach that focuses on reducing emissions from sources with higher risk of producing larger leaks. In the case of the T&S sector, these sources are reciprocating compressor rod packing, centrifugal compressor seals, compressor blowdown valves, compressor isolation valves and storage tank dump valves. This is substantiated by EPA's Subpart W data.

EPA cannot overlook the scientific studies and data that support focusing on the largest or "gross" emitters. A focus on those specific components or equipment with the greatest chance of leaking and the most significant leaks will provide benefits similar to a comprehensive leak detection program – with significantly reduced costs and burden on the operators and less risk of disruption of natural gas service to pipeline shippers and ultimately consumers.

The Proposed Rule includes a performance-based survey schedule that inappropriately depends on the percentage of compressor station component parts or equipment pieces that are leaking, rather than the volume of methane emissions from such leaks. In addition to conducting the survey, this approach requires a component count and tracking over time to assess the percentage of leaking components.

EPA defines "fugitive emissions component" as including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed-vent systems, thief hatches or other openings on a storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments and meters. This can be more than 1,000 components per new compressor station. This definition is not consistent with the traditional list of fugitive or modified components found in the proposed rule for processing plant "equipment" and will cause confusion within the oil and gas sector and LDAR contractors. The definition will also result in many more components than traditionally identified in LDAR programs, which will increase survey time and cost for transmission compressor stations.

Under EPA's Proposed Rule, an operator must survey the fugitive components at a compressor station and determine the percent of components that are leaking. An operator then must conduct quarterly surveys if more than three percent of the compressor station's component equipment fails to pass a leak inspection survey two consecutive times. Regardless of survey frequency, the Proposed Rule would require an operator to repair any leaks within 15 days.

Under this proposal, an operator would spend significant time searching to identify the source of very small leaks that individually result in a minimal volume of released methane. For example, EPA's proposed use of Optical Gas Imaging (OGI) equipment in the proposed rule could require an operator to detect and repair a small volume (often described as a wisp) from a compressor station piece of equipment that is equivalent to a small, 60 grams per hour release. The 60 grams per hour is less than three standard cubic feet per hour (SCFH). This level of leak rate detection in the Proposed Rule is equivalent to a "no leak" threshold for measurement procedures included in EPA's Subpart W reporting program. The approach would waste valuable resources addressing small leaks rather than allowing the focus to be identifying and eliminating the gross emitters.

Operators should be permitted to delay the repair of leaks emitting de minimis amounts of methane and those that are difficult to locate and costly to fix. This will allow operators to set priorities for repair of large or significant leaks, resulting in more meaningful emissions reductions.

EPA has not justified why the one percent of equipment threshold for triggering a NSPS work practice standard is reasoned decision-making. Nor has EPA demonstrated why a particular number of equipment leaks, i.e., one percent, without regard to the volume released by the leaking equipment, is justified or how the benefits of the rule outweigh its cost. These thresholds are all the more arbitrary in light of EPA's own data supporting the conclusion that the vast majority of emissions can be addressed by focusing on the limited number of gross emitters.

As EPA notes in the Regulatory Impact Analysis (RIA), methane is not a health pollutant. Consequently, EPA has discretion in setting reasonable repair response times. The number of compressor station leaks not repaired over a one-month to two-year time interval will not affect climate change because of the relative de minimis nature of those methane emissions in contrast to methane in the global atmosphere. Therefore, reasonable delay-of-repair provisions that would mitigate many of the adverse consequences that are likely to result from the rule are appropriate.

Response: We disagree with the commenter that the fugitive monitor program should focus on the volume of leaks rather than the percentage of leaking components. Even though some components have lower emissions factors in comparison to other components, the large number of these lower emission components makes up a large portion of emissions. As an example, connectors have an average fugitive methane rate of 0.147 thousand standard cubic feet per year, but the large number of them (3,068 at a model plant transmission station) results in a fugitive emission rate of 9.4 tons per year. We believe these fugitive emissions are considerable and believe that a frequent monitoring program will significantly reduce these emissions.

We believe that a majority of these small leaks can be repaired during the monitoring survey. For leaks that require parts, we are finalizing 30 days for the repair of fugitive emissions sources and an additional 30 days for resurvey of the repaired fugitive emissions components. We also are finalizing revisions to the delay of repair requirements. If a repair cannot be made due to a technical infeasibility that would require a blowdown or shutdown of the compressor station, or would be unsafe to repair by exposing personnel to immediate danger, the repair can be delayed until the next scheduled or emergency blowdown or station shutdown or within 2 years of finding the fugitive source of emissions, whichever is earlier.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 3

Comment: EPA's Proposed Fugitive Emissions Program Should Focus On "Gross Emitters."

EPA's fugitive emissions program should allow interstate transmission and underground storage operators to focus on locating and repairing large leaks that are a significant source of emissions rather than repairing all leaks regardless of size. As EPA recognizes in a specific request for comment on this issue, many studies have shown that a majority of emissions come from a minority of leaks. In fact, EPA itself has reported that data collected from Natural Gas STAR partners demonstrates that 95 percent of fugitive methane emissions at compressor stations are from 20 percent of the leaky components. EPA's proposed leak detection and repair program ignores this skewed distribution and would require replacement or repair of any fugitive emissions component that has evidence of fugitive emissions detected through visible confirmation from optical gas imaging (OGI). This would include very small leaks that would measure below 10,000 ppm, which is the leak definition in Subpart W and other NSPS authorizing the use of OGI. The proposed rule would mandate an inefficient allocation of resources, because it would require addressing any source of fugitive emissions at or above detection levels – regardless of the significance of the leak. EPA's proposed leak detection and repair (LDAR) program would sometimes require equipment to be shut down and blown down to complete the repair. In some cases, the blow down process would release emissions larger than the fugitive leak emissions the repair was intended to address. Such a program is neither environmentally beneficial nor practical.

It is also important to understand the relatively minor emissions associated with leaks that may be visible using OGI. A technical document on OGI in the docket provides data associated with evaluation tests for two different OGI cameras. A leak rate with a measured concentration of 1,000 to 2,000 ppmv was visible in these trials. That concentration was based on a release rate of about 10 grams per hour, which is equivalent to approximately 0.5 SCFH. Over an entire year, such a leak would result in about 2.5 TPY CO_2e emissions. In some cases, such a leak may be readily repairable (*e.g.*, tighten an accessible fitting). In other cases, such as minor leakage from a large compressor valve that is released through an elevated vent, repair costs or associated environmental impacts (*e.g.*, from blowdown) could result in the logical conclusion to not repair such a minor source of emissions.

Furthermore, by applying the proposed fugitive emissions program to any detected fugitive emissions, EPA has created a subjective standard for detecting leaks, which would be dependent on a host of conditions, including operator skill and weather, and difficult to enforce. Under "ideal" leak detection conditions, EPA's proposal could result in the identification of very small leaks that could be quite costly to prepare with little environmental benefit. The result being that EPA's proposal has overstated the benefits and understated the costs.

Instead, AGA recommends that EPA adjust its fugitive emissions program for compressor stations to focus on "gross emitters" by allowing approaches such as directed inspection and maintenance (DI&M) as an alternative to the proposed LDAR requirements. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are cost-effective to repair. DI&M is a proven effective programmatic approach to addressing fugitive emissions at compressor stations, as described in an EPA Natural Gas STAR lessons learned document.

Response: We disagree with the commenter that the fugitive monitor program should focus on "gross emitters". Even though some components have lower emissions factors in comparison to other components, the large number of these lower emission components makes up a large portion of emissions. As an example, connectors have an average fugitive methane rate of 0.147 thousand standard cubic feet per year, but the large number of them (3,068 at a model plant transmission station) results in a fugitive emission rate of 9.4 tons per year. We believe these fugitive emissions are considerable and believe that a frequent monitoring program will significantly reduce these emissions.

We disagree with the commenter in regards to the environmental benefits. We believe the monitoring program for compressor stations will reduce methane emissions by 28 tons per year at gathering and boosting stations, 32 tons per year at transmission stations, and 114 tons per year at storage facilities. We believe these are significant emissions reductions that could not be achieved through a directed maintenance and inspection program. Please see DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7. Therefore, we are finalizing quarterly fugitive monitoring for compressor stations.

Commenter Name: Andy McDonald
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6875
Comment Excerpt Number: 7

Comment: We recommend that EPA adjust its fugitive emissions program for compressor stations to focus on "gross emitters" by allowing approaches such as directed inspection and maintenance (DI&M) as an alternative to the proposed LDAR requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6874, Excerpt 3 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 4

Comment: EPA's Proposed Fugitive Emissions Program Should Focus On "Gross Emitters."

EPA's fugitive emissions program should allow interstate transmission and underground storage operators to focus on locating and repairing large leaks that are a significant source of emissions rather than repairing all leaks regardless of size. As EPA recognizes in a specific request for comment on this issue, many studies have shown that a majority of emissions come from a minority of leaks. In fact, EPA itself has reported that data collected from Natural Gas STAR partners demonstrates that 95 percent of fugitive methane emissions at compressor stations are from 20 percent of the leaky components. EPA's proposed leak detection and repair program ignores this skewed distribution and would require replacement or repair of any fugitive emissions component that has evidence of fugitive emissions detected through visible confirmation from optical gas imaging (OGI). This would include very small leaks that would measure below 10,000 ppm, which is the leak definition in Subpart W and other NSPS authorizing the use of OGI. The proposed rule would mandate an inefficient allocation of resources, because it would require addressing any source of fugitive emissions at or above detection levels – regardless of the significance of the leak. EPA's proposed leak detection and repair (LDAR) program would sometimes require equipment to be shut down and blown down to complete the repair. In some cases, the blow down process would release emissions larger than the fugitive leak emissions the repair was intended to address. Such a program is neither environmentally beneficial nor practical.

It is also important to understand the relatively minor emissions associated with leaks that may be visible using OGI. A technical document on OGI in the docket provides data associated with evaluation tests for two different OGI cameras. A leak rate with a measured concentration of 1,000 to 2,000 ppmv was visible in these trials. That concentration was based on a release rate of about 10 grams per hour, which is equivalent to approximately 0.5 SCFH. Over an entire year, such a leak would result in about 2.5 TPY CO2e emissions. In some cases, such a leak may be readily repairable (e.g., tighten an accessible fitting). In other cases, such as minor leakage from a large compressor valve that is released through an elevated vent, repair costs or associated environmental impacts (e.g., from blowdown) could result in the logical conclusion to not repair such a minor source of emissions.

Furthermore, by applying the proposed fugitive emissions program to any detected fugitive emissions, EPA has created a subjective standard for detecting leaks, which would be dependent on a host of conditions, including operator skill and weather, and difficult to enforce. Under "ideal" leak detection conditions, EPA's proposal could result in the identification of very small leaks that could be quite costly to prepare with little environmental benefit. The result being that EPA's proposal has overstated the benefits and understated the costs.

Instead, AGA recommends that EPA adjust its fugitive emissions program for compressor stations to focus on "gross emitters" by allowing approaches such as directed inspection and maintenance (DI&M) as an alternative to the proposed LDAR requirements. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are cost-effective to repair. DI&M is a proven effective programmatic approach to addressing fugitive emissions at compressor stations, as described in an EPA Natural Gas STAR lessons learned document.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6874, Excerpt 3 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 11

Comment: Additionally, WBI Energy recommends that the monitoring program for compressor stations focus on "gross emitters" and allow other methods such as directed inspection and maintenance programs as an alternative to the required monitoring proposed in the rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6874, Excerpt 3 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 6

Comment: We recommend revisions to the proposed leak monitoring and repair program, in particular the applicability of the leak monitoring and repair provision to the sources at existing facilities, the requirements to be met in the event of "modification" of existing sources and for new sources, and the requirements relating to repair. The leak monitoring and repair program, as proposed, will collectively result in significant additional compliance costs to the companies without realizing any appreciable environmental benefits in terms of reducing methane and/or VOC emissions. The program should focus on gross emitters related to new or modified equipment only.

The study [refers to "a recent study conducted by Colorado State University and the Environmental Defense Fund on emissions from the transmission and storage segment"], as well as a similar EDF-sponsored study for the gathering and boosting segment, indicates that the majority of fugitive emissions come from a relatively small number of gross leaks, specifically from compressor vents. A leak monitoring and repair program, requiring frequent inspections at every connector and valve at a compressor station, of which there could be thousands at one facility, is not a cost-effective approach to reducing emissions. This approach will result in the allocation of significant resources to find, inventory, and fix minor leaks in a never-ending 15-to-30 day cycle with minimal environmental benefit at best, or even additional emissions at worst from blowing down equipment to fix minor leaks. It should clearly not be EPA's intent to promulgate regulations without any significant environmental benefit and which are not cost effective.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 6.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 16

Comment: Instead of concentrating on large leaks, the proposed NSPS requires companies to devote additional resources to continuously check for small leaks that have a negligible impact on emissions. As discussed more thoroughly below, the proposed NSPS actually undermines the ability of operators to find new and more effective ways to address meaningful leaks, because it requires operators to focus time and resources on paperwork, rather than on developing new solutions to addressing leaks. EPA's strict timelines for detection and repair also leave operators with little flexibility to develop a compliance plan that works best for their facilities and will stymie voluntary industry innovations designed to address methane leaks. Given how far the compressor stations of an operator can be spread over remote areas, the additional annual costs for repairing equipment leaks at compressor stations to a leak definition of less than 10,000 ppm are expected to be significant. These smaller leaks simply do not justify the burden that they would place on these companies. As a result, Enterprise requests that EPA remove the LDAR requirements for compressor stations from the final rule. Instead, EPA should use the 40 C.F.R. part 98 reports to determine which facilities are a true concern, and develop compliance programs specifically targeted at those super emitters.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 6 and DCN EPA-HQ-OAR-2010-0505-6874, Excerpt 13.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 13

Comment: EPA Should Consider Emissions Information Reported Under Subpart W Of The GHGRP In Its Analysis And When Considering Whether Regulation Is Warranted.

As EPA recognizes, the Agency is collecting data from T&S compressor stations under Subpart W of the GHGRP, which requires annual leak surveys and compressor vent measurements for T&S compressor stations. Since 2011, thousands of measurements have been completed and reported to EPA. Because an objective of the GHGRP is to inform policy decisions, EPA should closely review

Subpart W reported data to understand implications for this initial regulation of methane emissions from natural gas operations. Although Subpart W only captures a subset of compressor station facilities, emissions can still be compared to EPA historical estimates by comparing on a common "activity data" basis. In other words, because EPA estimates for T&S in the annual national GHG inventory are often based on facility counts or compressor counts, comparisons of historical estimates could be made against emissions per facility or emissions per compressor values. A cursory review of the data indicates as follows:

- Focusing on "gross emitters" is warranted because a small number of measured leaks are responsible for the majority of compressor station leak emissions.
- Emissions from centrifugal turbines with wet seal degassing vents are significantly less than EPA's national inventory estimate.
- Pneumatic controller emissions for T&S are lower than EPA's national inventory estimate.

The first item supports focusing on gross emitters and considering alternatives such as DI&M, as AGA proposes above. The emission estimates for two affected sources – centrifugal compressors with wet seals and pneumatic devices – raise questions about the potential environmental benefit and the need for the proposed regulation. AGA recommends that EPA closely review emissions data from Subpart W and revisit its cost-benefit analysis in the Technical Support Document (TSD) based on more current emission estimates.

Response: In our re-evaluation of the TSD determination for the proposed rule, we considered both subpart W data and GHG Inventory data in the evaluation of fugitive emissions from compressor stations. Based on this re-evaluation, we determined that the GHG Inventory data provided the best estimate of fugitive emissions from compressor stations. We believe that looking at the fugitive emissions on a component basis provides a better estimate of the fugitive emissions and accounts for all leaks at the compressor station.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 32

Comment: EPA's Proposed LDAR Requirements Should Apply Comprehensively to both Components and Equipment at Affected Facilities

In addition to deploying LDAR at facilities across the oil and natural gas sector, it is important to ensure that operators comprehensively survey components and equipment at those affected facilities.

We support EPA's proposal to include both components and equipment in the definition of "fugitive emissions components" and note that sources like storage tank thief hatches and separator dump valves can be associated with significant emissions and should be part of leak inspection surveys. Indeed, field observations in Colorado using infrared cameras and other methodologies indicate that substantial emissions from controlled storage tanks can occur when emissions bypass control devices and are allowed to escape through open thief hatches and pressure relief valves (*e.g.*, when pressurized liquids from the separator are dumped into the atmospheric tank). Colorado now requires regular LDAR at new and existing storage vessels for this very reason. The Texas Commission on Environmental Quality has also noted the importance of these types of improper emissions. Recent studies of emissions from the gathering segment show substantial emissions from these sources, and underscore the importance of EPA's proposal including them within the scope of its LDAR requirements.

EPA's proposed definition of "fugitive emissions components" does, however, exclude "devices that vent as part of normal operations," like "natural gas driven pneumatic controllers." We urge EPA to revise the definition of "fugitive emissions components" to include intermittent-bleed pneumatic controllers. Recent studies have shown that these devices can function improperly and produce significant emissions, and an LDAR program could effectively identify and eliminate this pollution.

Several recent scientific studies have shown that intermittent controllers, which are designed to vent only periodically when actuating, can instead function improperly, vent continuously, and produce substantial emissions. In particular:

- **Allen et al (2015).** As part of the Phase II UT study, an expert review of the controllers with highest emissions rates concluded that some of the high emissions were caused by repairable issues, and "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."
- **City of Fort Worth Study.** The Fort Worth Study examined emissions from 489 intermittent-bleed pneumatic controllers, using IR cameras, Method 21, and a HiFlow sampler for quantification. The study found that many of these controllers were emitting constantly and at very high rates, even though the devices were being used to operate separator dump valves and were not designed to emit in between actuations. Average emission rates for the controllers in the Fort Worth Study were at a rate approaching the average emissions of a high-bleed pneumatic controller. According to the study authors, these emissions were frequently due to supposedly improperly functioning or failed controllers.
- **British Columbia Study.** The Prasino study of pneumatic controller emissions in British Columbia also noted the potential for maintenance issues leading to abnormally high bleed rates. Although the researchers did not identify a cause for these unexpectedly high emission rates, the results are consistent with the observation that maintenance and operational issues can lead to high emissions.

- **The Carbon Limits Study.** The Carbon Limits Report confirms these findings and concludes that LDAR programs may help to identify other improperly functioning devices like pneumatic controllers.

As the Fort Worth Study suggests, and the Carbon Limits study confirms, the same methods used for leak detection at valves, connectors, and other leaking components and equipment at oil and gas facilities can be used to spot significant operational issues at pneumatic controllers. This is particularly true of intermittent-bleed controllers, where an OGI survey revealing continuous emissions from an intermittent controller can alert operators to the problem. Moreover, if a comprehensive LDAR program is already being implemented at a facility, the marginal cost of extending that program to intermittent-bleed pneumatic controllers would likely be very modest, especially if an operator uses an OGI (e.g., IR camera) or similar technology to detect leaks. Accordingly, we strongly urge EPA to finalize an LDAR program that addresses all potential sources of leaks and inadvertent venting, including intermittent-bleed controllers.

EPA could ensure these devices are monitored by revising the definition of "fugitive emissions component" to exclude only "devices that vent **continuously** as part of normal operations, such as **continuous** natural gas-driven pneumatic controllers."

Response: The EPA disagrees with the commenter that intermittent bleed devices should be specifically covered by the fugitive emissions component definition. The data we have indicates that the emissions from intermittent pneumatic controllers are not significant and that the information presented by the commenter from the studies cited above, and as noted by the studies, reflect malfunctioning equipment that is not operating under normal conditions. Therefore, it is not appropriate to cover these sources under other provisions of the rule. We remind owners and operators of their general duty to minimize emissions. If an owner or operator discovers through audio, visual, olfactory or other means that an intermittent pneumatic controller is malfunctioning by venting continuously, the owner or operator must repair or replace the controller.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 10

Comment: Definition of "Fugitive Emissions Components"

In the proposal, EPA also introduces a new definition of "fugitive emissions components" for compressors stations that is unduly broad and inconsistent with EPA's prior NSPS provisions addressing fugitive emissions. Fugitive emissions components are defined in the proposal as:

any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, *instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.*

Proposed 40 C.F.R. § 60.5430a.

First, this definition marks a substantial departure from EPA's prior definitions in 40 C.F.R. Part 60 Subpart VVa, Subpart KKK, and in the original Subpart OOOO. Each of those Subparts is also intended to regulate fugitive emissions components and define the regulated components as "equipment." For example, pursuant to Subpart OOOO, the fugitive emissions components to be monitored—specifically, "equipment"—are defined as "each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart." 40 C.F.R. § 60.5430. EPA offers no explanation for deviating from its past precedent and defining fugitive emissions components more broadly in the proposed rule. See Dillmon v. NTSB, 588 F.3d 1085, 1089-90 (D.C. Cir. 2009) (citing FCC v. Fox Television Stations, Inc., 129 S. Ct. 1800, 1811 (2009)) ("Reasoned decision making … necessarily requires the agency to acknowledge and provide an adequate explanation for its departure from established precedent."); see also Motor Vehicle Mfrs. Ass'n, 463 U.S. at 42; AT&T Corp. v. FCC, 236 F.3d 729, 736-37 (D.C. Cir. 2001) (reasoned decision-making standard requires explanation for departure from prior decision).

In departing from its prior definitions of fugitive emissions components, EPA is inappropriately incorporating broad equipment categories rather than identifying actual components that may leak. Specifically, EPA is proposing to include entire systems such as closed vent systems, storage vessels, dehydrators, heaters, separators, instruments, meters, and pressure vessels within the definition of fugitive emissions components. But these types of equipment are not themselves sources of fugitive emissions. Instead, they contain specific components such as valves, connectors, flanges, compressor seals, and pump seals that are not intended to vent gas and, thus, may be sources of fugitive emissions. Rather than requiring monitoring surveys for broad equipment types, the definition of fugitive emissions components must be limited to the precise components that EPA believes may be a source of fugitive emissions. Unless the definition is narrowed to include only components rather than a collection of components and equipment types, the definition will be ambiguous and create uncertainty regarding the scope of the fugitive emissions monitoring program for both operators and regulatory agencies.

Second, EPA's proposal to leave the definition of fugitive emissions components open-ended will add unnecessary confusion to operators seeking to implement LDAR programs. Specifically, EPA includes in the definition of fugitive emissions components the phrase "including but not limited to." Given the open-ended nature of this proposed definition, it will be difficult for operators to determine which components meet EPA's proposed definition and obtain an accurate component count to determine a monitoring schedule. This uncertainty could also cause compliance confusion at a later date. A company's interpretation of "including but not limited to" could be entirely different than an inspector's interpretation leaving industry open to compliance actions in the future. GPA urges EPA to avoid such uncertainty and confusion by deleting this phrase from the definition of fugitive emissions components. Regulations are impermissibly vague if they fail to give "fair warning of what the regulations require." Freeman United Coal Mining Co. v. MSHA, 108 F.3d 358 (D.C. Cir. 1997); see also Utah Power & Light Co. v. Secretary of Labor, 951 F.2d 292, 295 n.11 (10th Cir. 1991). GPA's members are committed to working with EPA to reduce fugitive emissions from the gas gathering sector. However, a regulation that suggests a duty to monitor certain unnamed components does not give fair warning to operators of what is required of them as they seek to achieve those goals.

Third, EPA's proposed definition is internally inconsistent. After listing the various components that are included in the proposed definition, EPA states that "devices that vent as part of normal operations … are not fugitive emissions components …." 40 C.F.R. § 60.5430a.

However, this statement does not go far enough to clarify the definition and exclude devices that are designed to vent as a part of normal operation. While GPA agrees that this clarification is important, many of the specific components that are listed within the definition are designed to vent as a part of normal operation or for safety purposes. These components include thief hatches, agitator seals, distance pieces, crankcase vents, pump diaphragms, and instruments. Most of the items are designed to vent and would pose safety concerns if they did not. For example, crankcase vents are designed to vent gas in order for an engine or compressor to operate properly and safely. If the crankcase vent for an engine was not allowed to vent, blow-by gas going past the piston rings into the crankcase would continually build up pressure. This would either cause a large number of oil leaks or, if there were any heat in the system, a strong possibility of a crankcase explosion. While some newer engines may route the crankcase gases back to the intake system, it is very rare that engines older than five years are set up this way. Similarly, for a compressor, if the crankcase vent is not allowed to vent, pressure would build up in the compressor and oil would leak. Likewise, a blowdown vent does not produce fugitive emissions. It is merely a piece of pipe directing emissions from blowdowns into the atmosphere. The pressure inside a natural gas compressor must be relieved before it can be restarted. A common approach is to blow down the internal gas by opening a valve to vent the natural gas to the atmosphere through a blowdown vent which is an open-ended pipe or silencer stack. To avoid confusion about the appropriate scope of LDAR programs and to avoid monitoring of normal venting activities, GPA urges EPA to remove from the definition of fugitive emissions components, the components identified above that vent during normal operations.

Fourth, EPA's definition of fugitive emissions components overlaps with other regulatory requirements. For example, in the national emission standards for hazardous air pollutant regulations in 40 C.F.R. Part 63, Subpart HH, EPA requires that the closed vent system of a Subpart HH-applicable dehydrator be monitored annually via methods specified in 40 C.F.R. § 63.772(c). See 40 CFR § 63.773(c)(A). The inclusion of closed vent systems as a part of fugitive emissions components would make the monitoring requirement duplicative and subject certain components to multiple and potentially conflicting standards.

For the reasons described above, GPA urges EPA to revise its proposed definition of fugitive emissions components in 40 C.F.R. § 60. 5430a as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including ~~but not limited to~~ valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, ~~thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms,~~ and compressors, ~~separators, pressure vessels, dehydrators, heaters, instruments, and meters~~. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

Response: The EPA thanks the commenter for the thorough evaluation of issues related to the definition of fugitive emissions components. We realized that the definition as proposed was overly broad and a potential source of confusion for industry and regulators. We have revised the definition of fugitive emissions component. See sections VI.F.1.f and VI.F.2.e of the preamble to the final rule for a discussion of the new definition.

With respect to the points raised by the commenter, we have removed the equipment types and the phrase "including but not limited to", from the definition and have added clarifying language with respect to devices that vent as part of normal operations. Finally, we have clarified that the provisions apply only to closed vent systems that are not subject to section §60.5411a of the final rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 103

Comment: The Definition Of Fugitive Emissions Component Is Confusing, Which Leads To Duplicative Affected Facility Applicability Requirements For Leak Detection And Closed Vent Systems

The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. In those programs, including the one in Subpart OOOO and OOOOa for gas processing plants, fugitives emission components are defined as *Equipment*. While it may be appropriate to have a separate definition apart from that used in gas processing plants, it should be reflective of the Equipment definition and not be more expansive to include equipment that is neither a fugitive component nor part of another system. Our recommended text changes to the definition can be found at the end of this section (see Section 27.2.12).

Furthermore, the types of fugitive emissions components that EPA proposed is inconsistent with the types of components in Subpart W, which varies by reporting sector, but generally includes: valves, connectors, flanges, open-ended lines, pressure relief valves, control valves, block valves, orifice meters, regulators, pumps, and other (Tables W-1A through W-7 to Subpart W of Part 98). This will cause confusion between the two programs. Also, this definition is inconsistent with the definition used in NSPS VVa, KKK and GGGa. VVa defines equipment as *"each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart"* (§60.481a). Under KKK, EPA defined equipment as *"each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart"* (§60.631). NSPS GGGa defines equipment as *"each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment"* (§60.591a).

Since this proposal includes separate closed vent system monitoring requirements for what is essentially a collection of fugitive emission components, *closed vent system* requires its own definition so that closed vent system requirements can stand alone and are not subject to duplicative compliance requirements as currently proposed when also included in this definition. More detailed comments that address this issue for closed vent systems are found in Section 15.0 Other equipment inappropriately included in this definition includes:

"access doors, ..., thief hatches or other openings on storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters."

The equipment list above that should be excluded from the definition are not fugitive components, but rather parts of systems or equipment such as the separators, pressure vessels, dehydrators, and heaters that may have fugitive components, and fugitive component monitoring would be applicable when required. Thief hatches have complexities of operation and design as discussed in Section 26.0, thief hatch monitoring is NOT needed for storage vessels with no closed vent system since thief hatch design and operation is not important with low emission tank that already vents to atmosphere. Including thief hatches with CVS eliminates unnecessary monitoring in §60.5397a.

Vents are not fugitive components because they are designed to vent and compressors are covered separately in Subpart OOOO and OOOOa. Instruments and meters are not defined and some are designed to vent.

The following language in the definition should be removed as it is confusing and sets conditions upon which it may or may not be a fugitive component which creates a circular conundrum for a monitoring plan:

"Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions."

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 19

Comment: The list of fugitive components in Subpart OOOOa would include "any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters." This list is too broad because it would include equipment that is designed to vent for safety and other operational reasons, including thief hatches and engine crankcase vents.

It appears that EPA does not intend for the list of fugitive components to include equipment that is designed to vent, as the proposed definition provides that "[d]evices that vent as part of normal operations ... are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission." Accordingly, EPA should have no objection to deleting thief hatches and engine crankcase vents from the list, given that an integral part of the normal intended function of such equipment is to emit methane and other natural gas-related emissions.

It is important that EPA limit the list of fugitive emission components only to that equipment that is not designed to vent as part of its intended operations, so as to keep the rules' focus on equipment that emits fugitive emissions as the result of an abnormal, unintended condition that needs to be repaired. A report on the docket of this rulemaking makes clear that fugitive emissions "are *unintentional* losses and may arise due to normal wear and tear, improper or incomplete assembly of components, inadequate material specification, manufacturing defects, damage during installation or use, corrosion, fouling and environmental effects." Thus, removing thief hatches and crankcase vents from the list of fugitive components would bring the list more in line with the traditional concept of what constitutes a fugitive emission component - *i.e.,* a component that is emitting fugitives due to an unintended malfunction, rather than as a result of intended operations. Eliminating thief hatches and crankcase vents from the list would also have the benefit of reducing the number of individual components that would be subject to the extensive survey/repair/resurvey/recordkeeping/reporting requirements that EPA is currently proposing. The application of such onerous requirements should be as limited as possible, and in no event should such requirements extend to equipment that vents emissions as an integral and intended part of its operations. We note that EPA has not seen fit to include such an expansive list of fugitive emission components in other NSPS subparts; the leak detection and repair ("LDAR") rules in Subpart VVa, for example, list only the following covered equipment: "pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart." This is a far more realistic list than the proposed Subpart OOOOa list of fugitive emission components, and notably it does not include any equipment that is designed to vent as part of its intended operation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 26

Comment: The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. For example, in the NSPS OOOO requirements for gas processing plants, "fugitive emission components" are effectively included within the definition of *"equipment." See* 40 C.F.R. § 60.5430 (*"Equipment*, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.")

EPA has provided no rationale for such a significant deviation from the longstanding approach as reflected in NSPS OOOO. As a matter of regulatory consistency and efficient program implementation, the definition of "fugitive emissions component" in OOOOa should not be more expansive than other similar regulatory definitions in NSPS OOOO.

Moreover, the definition of "fugitive emissions component" above incorrectly includes equipment that should be listed as devices that vent as part of normal operations. Specifically, included within the definition of "fugitive emissions component"—but should not be—are "thief hatches or other openings on a storage vessels (part of closed vent system, not relevant to an uncontrolled storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters." 80 Fed. Reg. at 56,638. Each of these vents as part of normal operations, and must be allowed to within the confines of these pressurized systems for very serious safety and other operational
reasons.

In addition, "closed vent system" requires its own definition. The proposed rule conflates the separate closed vent systems with fugitive emission components. The closed vent system monitoring requirements can (and should) stand alone; otherwise, the rule creates duplicative compliance requirements. It may also result in unintended enforcement consequences.

If the fugitive emissions components definition is not changed to remove equipment that is designed to vent, the rule may be applied to tanks not subject to NSPS OOOO. We do not believe EPA intended this outcome, nor did it consider the costs or other impacts of this outcome. Put simply, this provision of the proposal contains very serious flaws, which do not account for operational realities at upstream oil and natural gas facilities, and is in need of significant changes prior to finalization.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 26

Comment: The rule incorrectly defines "fugitive emissions component"

The definition of fugitive emission component is inconsistent with historical definitions for other leak detection programs. For example, in the NSPS OOOO requirements for gas processing plants, "fugitive emission components" are effectively included within the definition of "equipment." 40 C.F.R. § 60.5430 ("Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.")

The proposed rule proposes the following definition of fugitive emissions component, which is notably more expansive:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump would be considered fugitive emissions.

80 *Fed. Reg.* at 56,638. EPA has provided no rationale for such a significant deviation from the longstanding approach as reflected in OOOO. As a matter of regulatory consistency and efficient program implementation, the definition of "fugitive emissions component" in NSPS OOOOa should not be more expansive than other similar regulatory definitions in OOOO.

Moreover, the definition of "fugitive emissions component" above incorrectly includes equipment that should be listed as devices that are designed to vent as part of normal operations. More specifically, included within the definition of "fugitive emissions component" are "thief hatches or other openings on a storage vessels (part of closed vent system, not relevant to an uncontrolled storage vessel) agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters." 80 *Fed. Reg.* at 56,638. Each of these types of equipment vents as part of normal operations, and must be allowed to do so within the confines of these engineered systems for very serious safety and other operational reasons.

In addition, "closed vent system" requires its own definition. The proposed rule conflates the separate and distinct closed vent system employed to capture emissions with components in VOC or oil and gas service that have fugitive emissions. The closed vent system monitoring requirements can (and should) stand alone; otherwise, the rule creates duplicative compliance requirements. It may also result *in* unintended enforcement consequences.

If the fugitive emissions components definition is not changed to remove equipment that is designed to vent, the rule may be applied to tanks not otherwise subject to the 2012 NSPS OOOO. We do not believe EPA intended this outcome, nor did it consider the costs or other impacts of this outcome. Put simply, this provision of the proposal contains very serious flaws, which do not account for operational realities at upstream *oil* and natural gas facilities, and is *in* need of significant changes prior to finalization.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 35

Comment: As written, the proposed definition [of "fugitive emissions component"] (1) unreasonably and unnecessarily overlaps with other provisions, and (2) is overly inclusive in that the definition erroneously includes a number of components that should be removed. The result of this broad definition is to bring within the ambit of the NSPS as many components as possible. This renders the definition overly burdensome and arbitrary in that it ultimately impedes the purpose and utility of the proposal.

In general, thief hatches should not be included in the definition of fugitive emission component. By design and function, thief hatches are routinely opened to allow access to the tank for gauging. These are not "fugitive" emissions in the common sense notion of that term. In addition, spring-loaded thief hatches function as pressure/vacuum vents to prevent an over- or under-pressure condition in the tank to prevent a catastrophic release. Again, such hatches are designed to vent as part of *normal operations*. The proposed definition of fugitive emission component provides "[d]evices that vent as part of normal operations, . . . are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission." Storage vessel affected facilities using a control device or routing emissions to a process have closed vent systems, thief hatches, or other openings on a storage vessel separately regulated by Subpart OOOOa and subject to periodic inspections. Pneumatic pumps and compressors are other affected facilities that may have closed vent systems separately regulated. Proposed Section 60.5411a(c)(2) provides, "[y]ou must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections." Proposed Section 60.5416a(c)(1) requires monthly inspections of each closed vent system "for defects that could result in air emissions." For covers, Section 60.5416a(c)(2) also requires monthly inspections "for defects that could result in air emissions." Absent a justification for including these components in the definition of "fugitive emissions component," the definition is overly burdensome. A further issue is that there are not emission factors available for these types of sources. The proposed definition should therefore be revised to remove closed vent systems, thief hatches or other openings on a storage vessel.

It is also unnecessary to include separators, pressure vessels, dehydrators, or heaters, since they would already be included to the extent they are equipped with valves, flanges and connectors, and other components. This equipment should be removed from the definition to eliminate redundancy. Furthermore, crankcase vents should also be removed from the definition of "fugitive emissions component," as such equipment "vents as part of normal operations." To otherwise include crankcase vents in the definition would cause it to become unworkable. In addition, while it makes sense for the definition of "fugitive emissions component" to include each pump, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in crude oil, hydrocarbon condensate or natural gas service, it should not include compressors, which are separately regulated. Fugitive emission component should therefore exclude certain equipment, including equipment in vacuum service, double block and bleed valves, lab sample analyzer vents and distance pieces.

Finally, the rule should also explicitly limit "fugitive emissions component" to those components in natural gas (including fuel gas), crude oil, or hydrocarbon condensate service to ensure that EPA limits the scope of the rule to the source category being regulated. Equipment leak components that are not in produced hydrocarbon service, such as those in methanol, glycol or other oilfield chemical or distillate fuel service, cannot be subject to OGI or Method 21 inspections. Such liquids "have the potential to emit VOC," but have a low vapor pressure and are not significant sources of fugitive emissions.

EPA should revise its proposed Section 5430a definition of "fugitive emissions component" as follows:

Fugitive emissions component means ~~any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including~~ each pump, pressure relief device, open-ended valve or line, valve, or flange or other connector that is in natural gas (including fuel gas), crude oil, or hydrocarbon condensate service. ~~but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not~~

~~considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.~~

Since the affected facilities at well sites and compressor stations includes the "collection of all fugitive emissions components," the recommended definition would suffice.

EPA might also address the concerns above by revising the "equipment" definition, which is proposed to be:

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of methane and VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

TXOGA is open to other solutions, provided that they do not bring into fugitive monitoring components that are not appropriately included in the rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 100

Comment: EPA MUST RESOLVE THE OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSTEM AND FUGITIVE EMISSION REQUIREMENTS

In §60.5416a, EPA proposes initial and continuous inspection and monitoring requirements for covers and closed vent systems. These requirements consist of a program to identify leaks on covers and closed vent systems and repair them. In addition, EPA proposed a fugitive emissions program in §60.5397a that is also based on identifying and repairing leaks. As proposed, §60.5397a will also apply to covers and closed vent systems, as the definition of "fugitive emissions component" includes "closed vent systems," and "thief hatches or other openings on storage vessels." This results in covers and CVS being subject to both the leak detection and repair requirements in §60.5397a and the leak detection and repair requirements in §60.5416a. This creates a situation which is unnecessarily duplicative and redundant. Table 26-1 provides a summary of these overlapping requirements. [Table 26-1 Summary of the Overlapping Closed Vent System and Cover Requirements in NSPS Subpart OOOO]

API does not believe that this was EPA's intention, as EPA did not include component counts and cost estimates for monitoring the storage vessel cover or the closed vent system with the LDAR cost estimates. EPA only included counts in the model plant for components for a wellhead, separator, heater, and dehydration unit according to the Technical Support Document (Table 5-4 and Table 5-5).

API believes that the appropriate and most effective solution is to require the same methodology to monitor the cover and CVS and other fugitive leaks, and that OGI is the most effective methodology. OGI can see the leaks regardless of the type of system. There is no need for additional monitoring on top of the OGI monitoring.

To avoid duplicative monitoring requirements, API recommends clearly defining "closed vent system" consistent with other NSPS Subpart definitions, that is entirely separate from "fugitive emission component". By having a separate definition for closed vent system, a subset of fugitive components is created for affected facilities with closed vent systems that are subject to fugitive monitoring requirements even if the rest of an existing site, for example, is not subject to fugitive monitoring requirements in §60.5397a. The net result is one consistent set of fugitive monitoring requirements that allows for use of OGI whether fugitive components are part of a closed vent system or part of another process.

Following are descriptions of these recommended improvements.

Define "Closed Vent System"

As noted above, API recommends that EPA add a definition of a closed vent system in §60.5430. The components of a closed vent system may have fugitive components included but also has additional components outside of fugitives that ensure the emissions are being routed to the control device. Under NESHAP Subpart HH, EPA defined closed vent system as

"Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards."

API recommends the same definition of closed vent system be added to §60.5430a with an additional clarification **(bold)** that would include covers in the definition. This would ensure that all of the leak detection and repair requirements would also apply to components and openings on covers.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.

API recognizes that there are a number of interrelated aspects of this definition and the requirements related to the definitions of "routed to a process or route to a process" and "fugitive emissions component", as well as the associated requirements. Due to the insufficient length of the comment period, API is not offering a comprehensive recommendation in these comments. However, API will provide supplementary information with such a recommendation following the end of the comment period.

Remove Cover and Closed Vent Systems Components from Definition of Fugitive Emissions Component

In order to totally resolve the redundancy in the cover and closed vent system and fugitive component requirements, the definition of "fugitive emissions component" in§60.5430a needs to be modified.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, ~~closed vent systems, thief hatches or other openings on a storage vessels,~~ agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

API has several other suggestions related to this definition. While they are not shown here since they are not related to closed vent systems and covers, they are provided and discussed in Section 27.2.1.

Remove Section 60.5416a

API recommends that all paragraphs of §60.5416a be removed. As shown in Table 26-2 every relevant requirement of §60.5416a will be addressed by referring to a requirement in §60.5397, or in the case of the bypass requirements, requirements in §60.5411a. In many cases, moving to the OGI-based requirements will result in a more robust program to identify and repair leaks from closed vent systems and cover components. For example, API's recommended changes would require OGI monitoring for all CVS and cover components, rather than the OVA inspection requirements in §60.5416a. [Table 26-2 Side-by-Side Comparison of §60.5416a and §60.5397a Closed Vent System and Cover Requirements]

The related recommended rule changes throughout Subpart OOOOa to refer to §60.5397a rather than §60.5416a are provided in section 26.4.

Recommended Changes to NSPS Subpart OOOOa Related to Closed Vent System and Cover Fugitive Monitoring

As noted above, API's recommendation is to have the covers and closed vent requirements throughout Subpart OOOOa refer to the fugitive monitoring and repair requirements in

§60.5397a rather than the inspection, monitoring, and repair requirements in §60.5416a. Following are the specific suggested regulatory changes.

§60.5397a(j) ~~For fugitive emissions components also subject to the repair provisions of §§60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers~~. You must comply with the requirements of paragraphs (j)(1) and (2) of this section.

§60.5410a(b)(4) You must conduct the initial ~~inspections~~ monitoring survey required in ~~§60.5416a(a) and (b)~~§60.5397(j).

§60.5411a(a)(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by ~~§60.5416a(b)~~ complying with the requirements for fugitive emission components in §60.5397a.

§60.5415a(e)(3)(ii)(A) You must comply with ~~§60.5416a(c)~~ the requirements for fugitive emission components in §60.5397a for each cover and closed vent system.

§60.5420a(c)

(5)(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8)~~, 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii)~~. You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(6) Records of each closed vent system and cover inspection monitoring survey required under ~~§60.5416a(a)(1) and (a)(2)~~§60.5397a(f)(g),(h) or (i) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or §60.5416a(c)(1) for storage vessels.

(7) Reserved ~~A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels.~~

(8) Reserved ~~If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or §60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.~~

(9) If you are subject to the closed vent system no detectable emissions requirements of ~~§60.5416a(b)~~ §60.5397a for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with ~~§60.5416a(b)~~ §60.5397a(k).

The Requirements Do Not Need to Address Covers on Uncontrolled Storage Vessels and Covers and Closed Vent Systems on Storage Vessels Subject to Legally and Practically Enforceable Requirements

The changes recommended by API above will eliminate the redundancy in requirements for covers and closed vent systems on centrifugal compressor, pneumatic pump, and storage vessel affected facilities under Subpart OOOOa.

Under the proposed scenario, covers on uncontrolled storage vessels would have been subject to the fugitive emissions requirements. These covers will not be subject to any leak monitoring and repair requirements under the changes recommended by API above. However, as discussed in the following, requiring these covers to be monitored would add no value. If a tank is uncontrolled (i.e. <6 tpy VOC uncontrolled) then leaks would be accounted for as part of the allowable emissions for the uncontrolled storage vessel. Thief hatches and pressure relief devices have an inherent leak rate since they are not welded shut. However, emissions from the thief hatch and pressure relief device are accounted for in the emission determined using EPA's AP-42 7.1 with TANKS 4.09 and when flash emissions are estimated.

Thief hatches that are weighted or spring tensioned serve as emergency overpressure relief devices in addition to providing a point of access for obtaining a sample of the material stored in the storage vessel or for gauging the liquid level. Thief hatches act in combination with the pressure/vacuum (P/V) relief devices to prevent overpressure and bursting of a tank. During normal operations, neither the P/V devices nor the thief hatch will open. In the rare occurrence of overpressure conditions, the P/V devices will open to vent tank vapors. If the P/V devices flow capacity is not sufficient to prevent further overpressure of the tank, then the thief hatch will open to provide additional venting capacity. Such an overpressure incident may be due to a rapid inflow of produced fluid/gas into the storage vessel if, for example, a separator "dump valve" sticks open or fails. The functionality of P/V devices and thief hatches as overpressure relief devices must be preserved to enable safe operation. If the storage vessel is not controlled, these devices are not acting as part of a closed vent system, but rather overpressure relief. Monitoring thief hatches can be complicated to determine the thief hatch is acting as pressure relief device or trying to distinguish the inherent leak rate of the device from a leak. Emissions from operation of a pressure relief device and the inherent leak rate would be considered process emission.

If the tank is controlled under another legally and practically enforceable mechanism like a state permit, the closed vent monitoring requirements for the storage system would be covered by the state, and thus would also be legally and practically enforceable.

Response: The EPA agrees with the commenter that the definition of fugitive emissions component as proposed did not clarify the intent to only apply to covers and closed vent systems that were not already subject to requirements of §60.5411a of the rule. Therefore, we have revised the definition in the final rule to clarify that the fugitive emissions provisions apply only to covers and closed vent systems not subject to §60.5411a. See sections VI.F.1.f and VI.F.2.e of the preamble to the final rule for a discussion on the revised definition of fugitive emissions component. We believe the requirements of sections §60.5411a and §60.5416a continue to be appropriate as prescribed in the rule.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 18

Comment: Issue Regulatory Clarifications- Other Party Equipment located at Well Site

The proposed rules appropriately require monitor surveys and repair of components and equipment located at an affected source well site. However, many well sites have equipment on location that they do not own nor operate. Examples may include compressor engines, dehydration systems, and meter runs which although may be located on the well site are not owned and operated by the well site Operator. The well site Operator may include these sources in the fugitive emissions monitor survey.

However, the Operator may not be allowed to conduct repairs on leaks observed on the equipment owned/operated by another entity. As such, the Operator should not be accountable for compliance elements such as conducting repairs, resurveying leaks or maintaining records for leaks on such equipment.

Furthermore, it would be inappropriate to shift the burden of conducting the monitor surveys to the owner/operator of this type of equipment. Not only would it be costly to send a monitor team to a well site to merely survey a meter run, the entity (usually a Gathering company) has no means of knowing if a well site is an NSPS OOOOa affected source site.

Recommendations:

SWN recommends the proposed rule be revised such that the well site LDAR requirements only apply to the equipment owned and operated by the Production company on the well site. This can be achieved by revising the definition of "fugitive emissions components"

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions. For Production companies, fugitive emissions components are only those located at the well site which are owned and operated by the Production company.

Response: The EPA disagrees with the commenter. The collection of fugitive emission components at a well site, regardless of the owner or operator, is the affected facility and is subject to the fugitive emissions monitoring and repair program requirements specified in §60.5397a, including . The introductory text of §60.5365a states that "[y]ou are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification or reconstruction after September 18, 2015." Therefore the owner or operator is responsible for complying with the applicable standards. The commenter should be mindful, however, of the definition of "owner or operator" in §60.2 of the General Provisions which states that owner or operator means "any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part." We believe that the resolution for any leaking components identified during surveys can be managed by the operator through cooperative agreements with other potential owners at the site.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 10

Comment: Definitions of "well site" and "fugitive emission components" are overly broad and nonsensical

EPA proposes to regulate the collection of "fugitive emission components" at a "well site." EPA explains that "under the proposed standards, the affected facility would be 'the collection of fugitive emission components at a well site" and defines well site as:

"one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at§ 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries). "

Specifically, the proposed definition of "well site" is ambiguous and overbroad in that it encompasses not only one or more wells, but also "production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad." As a consequence, the proposed rule envisions a "stationary source" that could encompass a broad and geographically dispersed system of wells and centralized batteries or natural gas treating and processing facilities, whether or not connected by pipeline, provided the collection of sites receives production from such wells. This approach could bring in emission units that are located large distances from the well-site and for that reason, is entirely unworkable. Measured against the statutory and regulatory definitions that have long defined the scope of NSPS requirements, the proposed well-site definition fails and is arbitrary and capricious. It is inconsistent with the statute's definition of "stationary source" which is "any building, structure, facility, or installation" emitting an NSPS regulated pollutant. Based on the above, EPA should correct these shortcomings by defining "well site" to mean "a surface site" containing one or more wells." Such a definition would define the affected facility in terms that are meaningful and commonly understood and in a manner consistent with the statutory definition of "stationary source" ("any building, structure, facility, or installation which emits or may emit any air pollutant"). Further, another major issue is that this definition could potentially cause confusion and expand the breadth of the source determination proposal as well.

Individual components that are to be included for "fugitive" emissions monitoring must be better defined and differentiated from components that are designed to emit a certain amount of natural gas under certain circumstances to release pressure for safety reasons, e.g., thief hatches and pressure relief valves, such as Enardo valves. Consistent with the EPA's own language, they define "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening." Venting of hydrocarbon emissions from thief hatches and pressure relief valves, that is reasonably required for maintenance, gauging, or safety of personnel and equipment cannot reasonably be considered "fugitive emissions" and therefore should not be considered an affected "fugitive emissions component."

Additionally, components of the storage vessels, e.g., closed cover/vent/control systems, already covered under Subpart OOOO for storage vessels should not be subject to additional requirements. In concurrence with TXOGA's comments, the proposed definition as written (1) unreasonably and unnecessarily overlaps with other provisions, and (2) is overly inclusive in that the definition erroneously includes an number of components that should be removed. This renders the definition overly burdensome and arbitrary in that it ultimately impedes the purpose and utility of the proposal.

Last, only components that contain or contact a process stream with hydrocarbons should be considered "fugitive emissions components", components in process streams consisting of glycol, amine, produced water, or methanol should not be considered "fugitive emissions components."

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 107 and DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 28 for discussion of the definition of well site. See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the revisions to the fugitive emissions component definition.

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 7

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 21c

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 21c

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 21d

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 9

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC;
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 7

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 7

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 7

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797/ Excerpt Number: 8

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 6

Comment: In addition, these vessels are equipped with openings known as "thief hatches" that are used by operators to measure the volume of oil inside the tank before and after transfers to shipping trucks. These and other openings are also used to check for, or repair potential problems with storage vessels. It is our understanding that the definition of "fugitive emissions component" intends to exempt these practices, so that emissions resulting from opening thief hatches and other openings on storage vessels during these routine operations will not be considered fugitive emissions. The definition explicitly references these openings, but it is our understanding, based on the language in§ 60.5411a(b)(2)-(3), that EPA only intends to require operators to equip these openings with proper mechanisms to ensure that the openings are properly seated and sealed when these are not being opened for the reasons enumerated in the regulations.

As we understand the Methane NSPS, well sites can meet the fugitive emissions requirements by ensuring that the seals on thief hatches do not allow for emissions when the hatch is closed. We do not read the Methane NSPS to prevent operators from opening thief hatches and other tank openings. We believe that this reading is in keeping with both the proposed regulatory text and EPA's current method of implementing Subpart OOOO. We would also note that many facilities already subject to Subpart OOOO currently use these same tanks and practices. We ask EPA to confirm that this reading is correct, and to add language to the definition of "fugitive emission component" clarifying that opening thief hatches and other openings that are opened for the reasons enumerated in § 60.5411a(b)(2) are considered "[d]evices that vent as part of normal operations" and are thus exempt from the definition of "fugitive emission component." As discussed more thoroughly below, this definition is necessary to prevent excessive burdens on upstream oil and gas operators.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the clarifying revisions to the fugitive emissions component definition.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 7

Comment: EPA's Definition of Component is Overly Broad and Vague. The definition of fugitive emissions component in the proposed rule (60.5430a) significantly expands the current understanding in the oil and gas industry of what qualifies as a "component". The definition also increases the ambiguity of a well-defined term ("component") by including what could be defined as well site equipment containing many different components (e.g. compressors, separators, pressure vessels, dehydrators, heaters, instruments, etc.). The proposed definition of fugitive emissions component also includes the language "including but not limited to ... " That language would leave individual companies, and even individual employees within a single company, with the task of determining what a component might be at each different site.

This lack of precision will almost certainly lead to significant variability from person to person and from company to company on what could be considered a fugitive emissions component. This ambiguity would most certainly lead to different physical counts of fugitive emissions components, even from one site to the next. It also creates the potential that federal and state agency enforcement personnel will conduct independent component counts and reach a result that is different from that reached in good faith by company personnel. What is needed here is a bright line definition that identifies the universe of "components" that are subject to OGI surveys (see below for suggested definition).

Noble also notes the significant difference in the way EPA proposes to define "components at well sites and compressor stations" on the one hand, and "equipment" at natural gas processing plants on the other. (See the table below**.)** [Note: Table presents lists of what constitutes equipment at processing plants versus the proposed fugitive emissions components.] EPA's definition of "equipment" at processing plants provides far greater clarity than does the definition of component. In the alternative, Noble suggests that EPA use the definition of "component" developed by the state of Colorado for use in a technology-based LDAR program. This definition provides the kind of bright line demarcation that is needed, and was developed in a process that included regulators, several oil and gas companies, and non-governmental organizations:

"Component" means each pump seal, flange, pressure relief device, connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process

streams consisting of glycol, amine, produced water, or methanol.
5 CCR 1001-9 § XVII.A.S.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the revisions to the fugitive emissions component definition.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 49

Comment: EPA's definition creates difficulties in application and uncertainties in the requirements for operators in determining whether a leak has occurred at certain "fugitive emissions components" as defined. In fact, a significant number of the fugitive emission components described in EPA's definition are designed to vent or leak. EPA specifically acknowledges that "[d]evices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-drive pumps, are not fugitive emissions insofar as the natural gas discharged from the device's vent is not considered a fugitive emission." Or, more clearly stated—an emission that passes through a vent, by EPA's own definition, is not a fugitive emission: "Fugitive emissions means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." EPA's definition acknowledges that certain types of sources at oil and natural gas facilities are designed to vent, and therefore, do not constitute fugitive emissions; however, EPA nonetheless (1) erroneously includes those sources in its definition of fugitive emissions component, and (2) appears to have too narrow an understanding of the scope of such sources.

EPA does not acknowledge that numerous other "components" listed in its definition of fugitive emissions component are designed to leak or vent, or simply, by their nature will leak or vent—which should be excluded from its proposed definition. For example, access doors, openings, thief hatches, other openings on a storage vessel, and other non-welded components (among others) are designed to leak or vent. As such, it would be difficult if not impossible for operators to discern whether the detected emissions are by design: the operator may have to disassemble the facility from the vent backward to determine the source of the emissions and whether it is a fugitive component. This exercise, not only likely ineffective, would also be incredibly costly and EPA does not include these costs in its cost-effective analyses. Moreover, many of these components are required by industry standards or other regulations (e.g., PHMSA) and vent to ensure safety of equipment and personnel. For example, due to temperature changes, atmospheric tanks are equipped with pressure vacuum relief valves, which vent for safety purposes (e.g., to avoid rupturing), and Kinder Morgan permits those emissions as working and breathing losses. To the extent that EPA's language intends to suggest that there is a determinable threshold, or amount, above which the component is "leaking" as opposed to properly venting, such a threshold would be incredibly difficult to determine and would be impossible to implement in practice.

Furthermore, compressors (both reciprocating and centrifugal) are their own affected facility sources, with separate and distinct requirements; and thus, regulation should not be duplicative by inclusion in this definition. And finally, separators, pressure vessels, dehydrators, and heaters are each large pieces of equipment and it would be unfeasible to treat them as single fugitive emission sources.

To address its concerns, Kinder Morgan proposes (as its preference) that EPA apply the existing definition of “equipment” (with minor revisions suggested below) from NSPS OOOO (40 C.F.R. § 60.5430), rather than creating yet another definition:

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks **of methane and** VOC from **an affected facility under this subpart** ~~onshore natural gas processing plants~~, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that is in VOC service or in wet gas service,~~ and any device or system required by those same standards and requirements in this subpart. **Devices that vent as part of normal operations are not fugitive emissions components.**

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the revisions to the fugitive emissions component definition.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 6

Comment: EPA has proposed to define "fugitive emissions component" as components with the potential to emit fugitive emissions, but not devices that vent as part of normal operation. The Division is concerned with EPA's inclusion of thief hatches in the list of components, due to the difference in Colorado’s regulation between "venting" and "leaking." If EPA does not determine that Colorado's LDAR program would demonstrate compliance with the NSPS OOOOa LDAR program, then the Division requests EPA consider the following experience and concerns about how to address emissions from storage tank thief hatches.

Based on Colorado's experience, storage tanks can be significant emission sources, particularly emissions from thief hatches due to high pressures and inadequate system design. Colorado’s regulation does not define a storage tank thief hatch as a component, but rather requires that owners or operators operate storage tanks without venting hydrocarbon emissions from the thief hatch. Colorado's "no venting" standard addresses emissions from storage tank thief hatches, pressure relief devices, or other access points during normal operations. The storage tanks subject to this control requirement are subject to monitoring requirements to ensure compliance with the "no venting" standard, but are not directly subject to Colorado’s LDAR program. The Division has found that sources and other entities have been confused by "venting" versus "leaking" concerning storage tanks, hence Colorado's development of the separate "no venting" standard described above. Colorado has acknowledged that these devices are meant to operate as safety devices, and thereby emit hydrocarbons in certain situations, but the Division has repeatedly found these devices venting (e.g., stuck open) during normal operations when the pressure relief device should not be activated.

In contrast, Colorado considers "leaking" as related to unintended emissions from components. White Colorado requires an owner or operator ensure that storage tank thief hatches, pressures relief valves, or other access points are closed and properly seated, we do not directly subject these devices to Colorado's LDAR program due to this difference between "venting" and "leaking." EPA regulation, like Colorado regulation, may also require storage vessel emissions resulting from flash, working, and breathing tosses be collected. In addition, EPA's Interpretation of Fugitive Emissions in Part 70 and 71 memorandum states that emissions that are collected are not fugitive emissions. The Division suggests EPA consider these concerns with storage vessel thief hatches when finalizing the NSPS OOOOa definition of fugitive emissions component. If EPA does not allow an adequate state program as an alternative to NSPS OOOOa LDAR, the Division suggests that EPA either remove thief hatch from the proposed fugitive emissions component definition, or clarify that thief hatches are included with "devices that vent as part of normal operations" and address thief hatch emissions through other requirements, such as how Colorado has done.

The Division also notes that Colorado's regulation defines component as each pump seal, flange, pressure relief device, connector and valve that contains or contacts a process stream with hydrocarbons. Colorado included the "process stream with hydrocarbons" qualifier to ensure consistency with current regulatory definitions of components in fugitive service, and to provide clarify that pressure relief valves, and other components, may be subject to Colorado's LDAR program. The Division suggests EPA include a similar qualifier in the NSPS OOOOa definition of fugitive emissions component.

Lastly, EPA solicited comment on whether the fugitive emissions requirements should apply to all fugitive emissions components at modified sites, or just to those components that are impacted by the modification. The Division believes that the NSPS OOOOa LDAR requirements should apply to all components at the well site or compressor station, and not just the components impacted by the modification. The Division is concerned about the difficulty in conducting compliance evaluations of essentially split facilities and components, if EPA finalizes requirements to inspect only components connected to a modification.

Response: The EPA thanks the commenter for the information on coordination of the fugitives emissions provisions with Colorado’s LDAR program. We have made revisions to the definition of fugitive emissions component that we believe better aligns the definition with existing requirements in state regulations. The final definition does not include venting sources such as thief hatches on uncontrolled storage vessels but has been revised to target sources of fugitive emissions (i.e., thief hatches on controlled storage vessels). See the response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the revisions to the fugitive emissions component definition. With respect to application of the provisions for modifications, the applicability is based on well sites or compressor stations. See sections VI.F.2.h. and VIII.G.1 of the preamble to the final rule.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 7

Comment: EPA Must More Accurately Define "Fugitive Emission Components" and Clarify the Meaning of Modification in the Context of EPA's Proposed Fugitive Emission Control Requirements

EPA must remove reference to the larger pieces of equipment in the 40 CFR § 60.5430 definition of "fugitive emission components" when the smaller components associated with each larger piece of equipment are also included. To clarify, EPA includes the following large pieces of production equipment in the "fugitive emission components" definition: compressors, separators, dehydrators and heaters. 80 Fed. Reg. at 56695. However, EPA also lists the smaller components associated with these larger pieces of equipment, including valves, connectors, pressure relief devices, and open-ended lines. Id. The redundancy in EPA's definition of "fugitive emission components" will likely create confusion. QEP requests that EPA's definition only refer to the actual components and not the type of production equipment where such components may be found.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the clarifying revisions to the fugitive emissions component definition.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 50

Comment: If, however, EPA moves forward with its proposed definition of “fugitive emissions component,” to address Kinder Morgan’s concerns, Kinder Morgan proposes the following revisions to EPA’s proposed definition, in the alternative:

means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, ~~access doors,~~ flanges, closed vent systems, ~~thief hatches or other openings on a storage vessels,~~ agitator seals, distance pieces, ~~crankcase vents, blowdown vents,~~ pump seals or diaphragms, ~~compressors, separators, pressure vessels, dehydrators, heaters, instruments,~~ and meters. Devices that vent as part of normal operations, including but not limited to ~~such as~~ natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components~~, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission~~. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

The alternative definition proposed by Kinder Morgan would also be consistent with the components that operators are required to monitor under Subpart W.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the revisions to the fugitive emissions component definition.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 16

Comment: Fugitive Emissions From Oil and Natural Gas Production Well Sites

We recommend the proposal for an initial survey of "fugitive emissions components" with the proposed definition in § 60.5430a to include, among other things, valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks using OGI technology.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the revisions to the fugitive emissions component definition.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 7a

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 6

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 5

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 5

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 5

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LL
Document Control Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 5

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 5

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 4b

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 21a

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 21a

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 21b

Comment: We also ask that EPA clarify that the leak detection and repair requirements for fugitive emissions at well sites and compressor stations will not prevent operators from using atmospheric tanks at these sites. While the proposed Methane NSPS exempts storage vessels with a PTE of less than 6 tpy from the definition of an affected facility for purposes of the storage vessel control rules found at §§ 60.5395a and 60.5397a, the Methane NSPS is unclear as to how these storage vessels with a PTE under 6 tpy will be treated under the fugitive monitoring requirements and how they fit within the definition of "the collection of fugitive emissions components" at a well site or compressor station. Thus, while it appears at first that storage vessels with less than 6 tpy of emissions do not have to meet additional requirements under the Rules, operators may nonetheless find themselves forced to make expensive upgrades to storage vessels in order to come into compliance with the fugitive monitoring requirements unless EPA clarifies the Methane NSPS.

Response: The EPA is clarifying that owner and operators may use atmospheric storage vessels at well sites and compressor stations. The collection of fugitive emissions components on an uncontrolled storage vessels is not subject to §60.5397a. However, atmospheric storage vessels may be a storage vessel affected facility if the potential VOC emissions are greater than or equal to six tons per year (see §60.5365a for more information). We do remind owners and operators of their general duty to minimize emissions. If an owner or operator discovers through audio, visual, olfactory or other means that equipment is malfunctioning, the owner or operator must repair or replace the equipment.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 7b

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 6

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 6

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 6

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 5

Commenter Name/Affiliation: Ben Shepperd / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 6

Commenter Name/Affiliation: Bradley C. Cross, President/Partner; Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 7

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 21b

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 21b

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 21c

Comment: In order to save the industry from unwarranted burdens further detailed below, we ask that EPA clarify that the normal venting of gas from atmospheric tanks is not considered a fugitive emission. The definition of "fugitive emission component" currently exempts "[d]evices that vent as part of normal operations." Atmospheric tanks are designed to vent VOC and methane emissions for both safety and pragmatic reasons. As explained above, these tanks must "breathe" in order to let off excess pressure and prevent the tank from becoming a safety hazard. EPA should clarify that these atmospheric tanks are vented as part of normal operations, and that the venting is therefore exempt from the definition of "fugitive emissions component" in the Methane NSPS.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 7a.

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 6

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 5

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 5

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 5

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LL
Document Control Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 5

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 5

Comment: We also ask that EPA clarify that the leak detection and repair requirements for fugitive emissions at well sites and compressor stations will not prevent operators from using atmospheric tanks at these sites. While the proposed Methane NSPS exempts storage vessels with a PTE of less than 6 tpy from the definition of an affected facility for purposes of the storage vessel control rules found at §§ 60.5395a and 60.5397a, the Methane NSPS is unclear as to how these storage vessels with a PTE under 6 tpy will be treated under the fugitive monitoring requirements and how they fit within the definition of "the collection of fugitive emissions components" at a well site or compressor station. Thus, while it appears at first that storage vessels with less than 6 tpy of emissions do not have to meet additional requirements under the Rules, operators may nonetheless find themselves forced to make expensive upgrades to storage vessels in order to come into compliance with the fugitive monitoring requirements unless EPA clarifies the Methane NSPS.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 7.

We also ask that EPA clarify that the leak detection and repair requirements for fugitive emissions at well sites and compressor stations will not prevent operators from using atmospheric tanks at these sites. While the proposed Methane NSPS exempts storage vessels with a PTE of less than 6 tpy from the definition of an affected facility for purposes of the storage vessel control rules found at §§ 60.5395a and 60.5397a, the Methane NSPS is unclear as to how these storage vessels with a PTE under 6 tpy will be treated under the fugitive monitoring requirements and how they fit within the definition of "the collection of fugitive emissions components" at a well site or compressor station. Thus, while it appears at first that storage vessels with less than 6 tpy of emissions do not have to meet additional requirements under the Rules, operators may nonetheless find themselves forced to make expensive upgrades to storage vessels in order to come into compliance with the fugitive monitoring requirements unless EPA clarifies the Methane NSPS.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 7.

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 21

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882
/ Excerpt Number: 21

Commenter Name / Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control / Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 21

Comment: We also ask that EPA clarify that the leak detection and repair requirements for fugitive emissions at well sites and compressor stations will not prevent operators from using atmospheric tanks at these sites. While the proposed Methane NSPS exempts storage vessels with a PTE of less than 6 tpy from the definition of an affected facility for purposes of the storage vessel control rules found at §§ 60.5395a and 60.5397a, the Methane NSPS is unclear as to how these storage vessels with a PTE under 6 tpy will be treated under the fugitive monitoring requirements and how they fit within the definition of "the collection of fugitive emissions components" at a well site or compressor station. Thus, while it appears at first that storage vessels with less than 6 tpy of emissions do not have to meet additional requirements under the Rules, operators may nonetheless find themselves forced to make expensive upgrades to storage vessels in order to come into compliance with the fugitive monitoring requirements unless EPA clarifies the Methane NSPS.

In order to save the industry from unwarranted burdens further detailed below, we ask that EPA clarify that the normal venting of gas from atmospheric tanks is not considered a fugitive emission. The definition of "fugitive emission component" currently exempts "[d]evices that vent as part of normal operations." Atmospheric tanks are designed to vent VOC and methane emissions for both safety and pragmatic reasons. As explained above, these tanks must "breathe" in order to let off excess pressure and prevent the tank from becoming a safety hazard. EPA should clarify that these atmospheric tanks are vented as part of normal operations, and that the venting is therefore exempt from the definition of "fugitive emissions component" in the Methane NSPS.

In addition, these vessels are equipped with openings known as "thief hatches" that are used by operators to measure the volume of oil inside the tank before and after transfers to shipping trucks. These and other openings are also used to check for, or repair potential problems with storage vessels. It is our understanding that the definition of "fugitive emissions component" intends to exempt these practices, so that emissions resulting from opening thief hatches and other openings on storage vessels during these routine operations will not be considered fugitive emissions. The definition explicitly references these openings, but it is our understanding, based on the language in§ 60.5411a(b)(2)-(3), that EPA only intends to require operators to equip these openings with proper mechanisms to ensure that the openings are properly seated and sealed when these are not being opened for the reasons enumerated in the regulations.

As we understand the Methane NSPS, well sites can meet the fugitive emissions requirements by ensuring that the seals on thief hatches do not allow for emissions when the hatch is closed. We do not read the Methane NSPS to prevent operators from opening thief hatches and other tank openings. We believe that this reading is in keeping with both the proposed regulatory text and EPA's current method of implementing Subpart OOOO. We would also note that many facilities already subject to Subpart OOOO currently use these same tanks and practices. We ask EPA to confirm that this reading is correct, and to add language to the definition of "fugitive emission component" clarifying that opening thief hatches and other openings that are opened for the reasons enumerated in §60.5411a(b)(2) are considered "[d]evices that vent as part of normal operations" and are thus exempt from the definition of "fugitive emission component." As discussed more thoroughly below, this definition is necessary to prevent excessive burdens on upstream oil and gas operators.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 7 regarding atmospheric tanks and DCN EPA-HQ-OAR-2010-0505-7062, Excerpt 32 regarding clarifying revisions to the fugitive emissions component definition.

Commenter Name: Dad G. LeRoy
Commenter Affiliation: Legacy Reserves Operating LP
Document Control Number: EPA-HQ-OAR-2010-0505-6882
Comment Excerpt Number: 21

Comment: We also ask that EPA clarify that the leak detection and repair requirements for fugitive emissions at well sites and compressor stations will not prevent operators from using atmospheric tanks at these sites. While the proposed Methane NSPS exempts storage vessels with a PTE of less than 6 tpy from the definition of an affected facility for purposes of the storage vessel control rules found at §§60.5395a and 60.5397a, the Methane NSPS is unclear as to how these storage vessels with a PTE under 6 tpy will be treated under the fugitive monitoring requirements and how they fit within the definition of "the collection of fugitive emissions components" at a well site or compressor station. Thus, while it appears at first that storage vessels with less than 6 tpy of emissions do not have to meet additional requirements under the Rules, operators may nonetheless find themselves forced to make expensive upgrades to storage vessels in order to come into compliance with the fugitive monitoring requirements unless EPA clarifies the Methane NSPS.

In order to save the industry from unwarranted burdens further detailed below, we ask that EPA clarify that the normal venting of gas from atmospheric tanks is not considered a fugitive emission. The definition of "fugitive emission component" currently exempts "[d]evices that vent as part of normal operations." Atmospheric tanks are designed to vent VOC and methane emissions for both safety and pragmatic reasons. As explained above, these tanks must "breathe" in order to let off excess pressure and prevent the tank from becoming a safety hazard. EPA should clarify that these atmospheric tanks are vented as part of normal operations, and that the venting is therefore exempt from the definition of "fugitive emissions component" in the Methane NSPS.

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As we understand the Methane NSPS, well sites can meet the fugitive emissions requirements by ensuring that the seals on thief hatches do not allow for emissions when the hatch is closed. We do not read the Methane NSPS to prevent operators from opening thief hatches and other tank openings. We believe that this reading is in keeping with both the proposed regulatory text and EPA's current method of implementing Subpart OOOO. We would also note that many facilities already subject to Subpart OOOO currently use these same tanks and practices. We ask EPA to confirm that this reading is correct, and to add language to the definition of "fugitive emission component" clarifying that opening thief hatches and other openings that are opened for the reasons enumerated in §60.5411a(b)(2) are considered "[d]evices that vent as part of normal operations" and are thus exempt from the definition of "fugitive emission component." As discussed more thoroughly below, this definition is necessary to prevent excessive burdens on upstream oil and gas operators.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 7 regarding atmospheric tanks and DCN EPA-HQ-OAR-2010-0505-7062, Excerpt 32 regarding clarifying revisions to the fugitive emissions component definition.

Commenter Name: Denzil R. West, Vice President
Commenter Affiliation: Reliance Energy, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6915
Comment Excerpt Number: 21

Comment: We ask EPA to further clarify that even if a well site is modified and becomes subject to the fugitive-emissions monitoring portions of the Methane NSPS, no existing storage vessel will be required to comply with the new control requirements in the Methane NSPS, unless the existing storage vessel is itself modified or reconstructed as defined by the Methane NSPS; and to confirm that these sets of requirements have independent triggers in the Methane NSPS.

We also ask that EPA clarify that the leak detection and repair requirements for fugitive emissions at well sites and compressor stations will not prevent operators from using atmospheric tanks at these sites. While the proposed Methane NSPS exempts storage vessels with a PTE of less than 6 tpy from the definition of an affected facility for purposes of the storage vessel control rules found at §§ 60.5395a and 60.5397a, the Methane NSPS is unclear as to how these storage vessels with a PTE under 6 tpy will be treated under the fugitive monitoring requirements and how they fit within the definition of "the collection of fugitive emissions components" at a well site or compressor station. Thus, while it appears at first that storage vessels with less than 6 tpy of emissions do not have to meet additional requirements under the Rules, operators may nonetheless find themselves forced to make expensive upgrades to storage vessels in order to come into compliance with the fugitive monitoring requirements unless EPA clarifies the Methane NSPS.

In order to save the industry from unwarranted burdens further detailed below, we ask that EPA clarify that the normal venting of gas from atmospheric tanks is not considered a fugitive emission. The definition of "fugitive emission component" currently exempts "[d]evices that vent as part of normal operations." Atmospheric tanks are designed to vent VOC and methane emissions for both safety and pragmatic reasons. As explained above, these tanks must "breathe" in order to let off excess pressure and prevent the tank from becoming a safety hazard. EPA should clarify that these atmospheric tanks are vented as part of normal operations, and that the venting is therefore exempt from the definition of "fugitive emissions component" in the Methane NSPS.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 9

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC;
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 7

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 7

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 7

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797/ Excerpt Number: 8

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 6

Commenter Name: David M. Babson
Commenter Affiliation: Union of Concerned Scientists (UCS)
Document Control Number: EPA-HQ-OAR-2010-0505-6858
Comment Excerpt Number: 2

Comment: We are pleased that EPA has extended regulations to downstream sources such as those in the transmission and storage stages of the oil and natural gas supply chain. We also hope that EPA will clarify that its requirements for leak detection and repair extend to all known existing sources of methane that may not have been explicitly identified in its proposal. If there are known sources of methane (from equipment or axillary operations) that are not explicitly identified, or are not dual sources of VOCs and methane, EPA should clarify that those emissions will be regulated or justify why they should not be considered. Omitted methane sources could account for substantial methane emissions, and low cost controls are available for all of them.

Response: The EPA appreciates your support of the proposed requirements, and we believe that the rule addresses most of the significant sources of fugitive emissions of methane and VOC from the oil and natural gas sector. Owners and operators also have a general duty to minimize emissions. If an owner or operator discovers through audio, visual, olfactory or other means that an equipment is malfunctioning, the owner or operator must repair or replace the equipment.

Commenter Name: P. DeMarco
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5167
Comment Excerpt Number: 6

Comment: Strengthen the requirements for documentation and reporting of leaks at all stages of the operations: Pre-production, Production, Processing and Transmission. Establishing required protocols for monitoring and reporting leakages of methane and volatile organic compounds will contribute to the understanding of this entire system.

Response: We believe that the rule as finalized addresses most of the significant sources of fugitive emissions of methane and VOC from the oil and natural gas sector. We have included comprehensive recordkeeping and reporting provisions into the rule, which includes recordkeeping and reporting for fugitive emissions monitoring surveys. While we have not developed a monitoring protocol, we do not believe that lack of standardization will render the fugitive monitoring program ineffective. We believe that the requirements outlined in the final rule are enough to ensure that effective surveys are being performed.

Commenter Name: P. DeMarco
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5167
Comment Excerpt Number: 12

Comment: Require Leak detection and repair (LDAR) programs for all stages of oil and gas development.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6858, Excerpt 2.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 17

Comment: Concho disagrees with EPA's assessment that emissions from thief hatches and pressure relief devices are fugitive in nature. These emissions are minor and occur as a part of operations. Emissions arising from storage vessels which are maintained at atmospheric pressure cannot be routed to a closed vent system. As an upstream operator, Concho's production stream is dynamic and the composition and volumes of fluids can vary greatly. Due to this, thief hatches and pressure relief devices allow storage vessels to operate safely under a multitude of operational conditions. Thief hatches are designed to release vapors during normal operations. Concho encourages EPA to regulate thief hatches as components with permissible emission rates.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 4

Comment: EPA should add language to clarify that well sites subject to the proposed rule may continue to use atmospheric tanks to store oil. The proposed rule should clearly state this allowance to avoid confusion with current Subpart OOOO regulation and to avoid unintended cost and safety concerns related to replacing atmospheric storage tanks with pressurized storage tanks. Emissions resulting from ordinary venting of atmospheric tanks and the activities outlined in §60.5411a(b)(2) should not be considered "fugitive emissions components" and would therefore not be subject to the fugitive emissions monitoring rules. Emissions from storage vessels that are sent to a vapor recovery unit (VRU) that complies with EPA's regulations are not counted towards a storage vessel's 6 tons per year potential to emit (PTE).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 7.

Commenter Name: W. Michael Scott, General Counsel
Commenter Affiliation: Trilogy Operating, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6603
Comment Excerpt Number: 33

Comment: In addition, there is too much ambiguity surrounding what qualifies as a "fugitive emissions component" under the Methane NSPS. As a result, there is a significant risk that operators will unintentionally leave "components" out of their surveys, only to find out later that they are out of compliance as a result. Without a clearer definition of "fugitive emission component," well site or compressor station operators cannot be certain that they have actually included all of the "components" in a survey, and thus made all of the necessary repairs after a survey. The Methane NSPS also adjusts the frequency of survey requirements from semi-annually to annually, or from semi-annually to quarterly, based on the percentage of components found to be leaking during two consecutive surveys.

EPA should provide enforcement safe harbors during the first two years of implementation to protect operators who unwittingly miscount their components.

Response: The EPA agrees that ambiguity in the fugitive emissions component definition as proposed should be addressed and has revised the definition in the final rule. See sections VI.F.1.f and VI.F.2.e of the preamble to the final rule for a discussion of the clarifying revisions to the definition. The EPA disagrees that provisions for safe harbor based on misinterpretation of the requirements is necessary. We believe that the changes to the fugitive emissions component definition will alleviate the commenter's concern. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 9

Commenter Name/Affiliation: Michael Hollis /Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 27a

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915/ Excerpt Number: 26a

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968/ Excerpt Number: 23a

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978/ Excerpt Number: 23a

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 30

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 31

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 31

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 32

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 31

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 69

Commenter Name/Affiliation: Michael Hollis /Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 27a

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915/ Excerpt Number: 26a

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968/ Excerpt Number: 23a

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978/ Excerpt Number: 23a

Comment: In addition, there is too much ambiguity surrounding what qualifies as a "fugitive emissions component" under the Methane NSPS. As a result, there is a significant risk that operators will unintentionally leave "components" out of their surveys, only to find out later that they are out of compliance as a result. Without a clearer definition of "fugitive emission component," well site or compressor station operators cannot be certain that they have actually included all of the "components" in a survey, and thus made all of the necessary repairs after a survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 33.

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 35

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 36

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 36

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 37

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 36

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 73

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 31

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 25

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 30

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 27

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 26

Comment: EPA should clarify the definition of "fugitive emissions component" and should provide enforcement safe harbors during the first two years of implementation to protect operators who unwittingly miscount their components.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 33.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 12

Comment: Fugitive emission component definitions should not include process components such as dehydrators, crankcase vents, heaters, packing vents, pneumatic controllers and other point sources of minor significance.

Response: See the responses to DCN EPA-HQ-OAR-2010-0505-7062, Excerpt 32, and EPA-HQ-OAR-2010-0505-6881, Excerpt 10, for a discussion of the clarifying revisions to the fugitive emissions component definition.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 15

Comment: The fugitive emissions requirements should apply only to the fugitive sources that are connected to any new or modified compressor and should not apply to all of the fugitive emissions sources at the compressor station for stations with new or modified compressors. The latter would be unduly burdensome and contrary to EPA's intent for the NSPS program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 46

Comment: As an initial matter, Kinder Morgan has concerns regarding several of the definitions utilized in EPA's proposed fugitive emission/leak detection program proposed in the Proposed NSPS OOOOa Rule. Specifically, Kinder Morgan has concerns with the definitions of (1) well site and (2) fugitive emissions component.

EPA's proposed definition fails to account for the fact that certain support equipment (of the same type described by EPA in its definition of well site) are often not located at the well site, and may be owned and operated by companies other than the producer—namely by the company providing gathering services to one or more producers. As a result, EPA's definition could inadvertently include these facilities in the definition of a well site—a result that does not appear to be intended by EPA's proposed language or evaluated as part of EPA's cost analyses. Importantly, the producer may not have access to these support facilities and most certainly has no ability to make necessary repairs and conduct re-monitoring at these facilities. As such, it would be difficult, if not impossible for producers to conduct leak detection and repair at these facilities. In contrast, but with similar consequences, the owners of the gathering facilities do not have ownership or control over the well sites that those support facilities service. Thus, companies such as Kinder Morgan would have neither knowledge nor control over additions, modifications, or revisions made at the well site that could trigger application of NSPS OOOOa to such support facilities, should such support facilities be inadvertently included in the definition of well site. To avoid this unintentional result, EPA's definition of well site should be clarified to indicate that EPA intends to include only those tank batteries (and other described support facilities) owned and operated by the producer of the well. To address these concerns, Kinder Morgan proposes the following specific language revision to EPA's definition of well site.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad owned or **operated by the producer**. For the purposes of the fugitive emissions standards at 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries) **and owned or operated by the producer**.

Response: The EPA disagrees with the commenter that the rule must specifically clarify ownership. The collection of fugitive emission components at a well site, regardless of ownership, is the affected facility and is subject to the fugitive emissions monitoring and repair program requirements specified in §60.5397a, including . The introductory text of §60.5365a states that "[y]ou are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification or reconstruction after September 18, 2015." Therefore the owner or operator is responsible for complying with the applicable standards. The commenter should be mindful, however, of the definition of "owner or operator" in §60.2 of the General Provisions which states that owner or operator means "any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part." We believe that the resolution for any leaking components identified during surveys can be managed by the operator through cooperative agreements with other potential owners at the site. We are further clarifying the boundaries of a well site for purposes of the fugitive monitoring requirements. Our intent is to limit the oil and natural gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant. Therefore, the collection of fugitive emissions components within this boundary are a part of the well site.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 27

Comment: The definitions of "well site" and "fugitive emissions component" should be clarified.

Fugitive emissions are defined at 40 CFR Part 52(b)(20) as: …those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. The inclusive definition of "well site" in Subpart OOOOa includes "…all ancillary equipment in the immediate vicinity of the well that are necessary for or used in production and may include such items as separators, storage vessels, heaters, dehydrators, or other equipment at the site." The definition of "fugitive emissions component" clearly defines the nature of fugitive emissions from a well site but also references "other openings in storage vessels" and "dehydrators". The definition of fugitive emissions should be revised to clearly state that emissions from uncontrolled tank vents and uncontrolled dehydrator vents are not fugitive emissions.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the clarifying revisions to the fugitive emissions component definition.

Commenter Name: Comment submitted by Todd Parfitt, Director
Commenter Affiliation: Wyoming Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2010-0505-6993
Comment Excerpt Number: 4

Comment: Emissions from improperly designed or maintained equipment are not fugitive emissions

The EPA proposed a definition for fugitive emissions component that includes pressure relief devices, access doors, thief hatches, and other openings on a storage vessels. These types of equipment are often fitted with seals that may leak VOC emissions during normal operation and therefore these sources should be included in any applicable FM plan. However, it is important to note that improperly designed or maintained equipment can result in significant excess emissions. Examples of improperly designed equipment include ENARDO valves over pressurizing and failure of thief hatches to reseat after over pressurizing. An example of improperly maintained equipment is a thief hatch left open after an operator gauges the tank. AQD considers excess emissions from improperly designed or maintained equipment to be permit violations and has taken enforcement actions to remedy such operation. The EPA must clarify whether excess emissions resulting from improperly designed or maintained equipment that meet the definition of fugitive emissions component are considered normal operation.

Response: We agree with the commenter that significant fugitive emissions can occur from improperly designed or maintained components and are not a part of normal operations. The final rule seeks to reduce fugitive emissions from components, such as valves, connectors and flanges that may emit VOC or methane emissions resulting from normal operations (for example wearing down of seals over time) by requiring owners and operators to implement a fugitive emissions monitoring and repair program for the collection of fugitive emissions components at well sites and compressor stations. However, we note that the fugitive emissions monitoring program does not include sources of vented emissions such as a thief hatch on an uncontrolled storage vessel. We have modified the proposed fugitive emissions component definition to focus on sources of fugitive emissions and not vented emissions. See the response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the clarifying revisions to the fugitive emissions component definition.

Commenter Name: Jack Schwaller
Commenter Affiliation: HOERBIGER Corporation of America, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6799
Comment Excerpt Number: 7

Comment: <u>Regulation clarifications</u>: Does this section apply to rod packing?

1. **If so, the indication of seal failure is too limited. OGI (Optical Gas Imaging) method alerts when a problem is extreme. Need more options for earlier indication of seal degradation.**
2. **<u>Problem:</u>** OGI just identifies that leak exists and is not accurate. It is difficult to identify marginal situations the readings are too subjective and it is expensive.
3. **<u>Points and methods of indication or measurement</u>**
    1. Gas mass flow measurement can be easily made at the vent and distance piece. Most all units have existing pipe connections. Testing is fast and even easier to do if additional unit "plumbing" is installed.
    2. RTD temperature readings can indicate gas leakage inside the case assembly at the onset of seal failure with an increase in temperature (common used in the process industry). Easy to modify existing seal assemblies. This will not quantify leakage amount though.

Response: The fugitive emissions requirements do not apply to rod packing for reciprocating compressors because this is a regulated source under the rule. However, an OGI survey may identify leaking seals and alert the operator of the need for maintenance or repair. We remind owners and operators of their general duty to minimize emissions, which would include fixing leaking equipment not included under the definition of fugitive emissions component.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 32

Comment: Additionally, the PBPA proposes that only components in gas service be required to be surveyed. This would greatly reduce any required survey time.

Further, components which are attached to lines handling emulsions, oil, or water should be exempted from survey requirements.

Response: The definition of fugitive emission component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station. If the components which are attached to lines handling emulsions, oil, or water do not have the potential to emit methane or VOC, then they are not covered by the rule. See the response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10 for a discussion of the clarifying revisions to the fugitive emissions component definition.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute

Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 135

Comment: 27.4.13 Application of Fugitive Emission Requirements at Modified Sites

EPA requested comment on whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well**.**

For well sites, it is more complicated and difficult to manage to do fragmented LDAR based on difference applicability and different frequencies. Similarly it is complicated and difficult to manage a partial LDAR applied to different equipment or components at a given site. If a company is going to conduct LDAR for a specific piece of equipment at a site, it is just as efficient to scan the entire site. API supports annual LDAR for all the equipment located at an applicable well site.

Response: The EPA agrees with the commenter that establishing a survey requirement for only those components connected to the modified well would be too confusing and arduous. Additionally, we note that because the affected facility is the collection of fugitive emission components at a well site and not on a well and the potential emissions of the well site would increase, we believe that the modification should trigger fugitive emission monitoring for the entire well site.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 18

Comment: Hess proposes that the Proposed OOOOa Rule allow standard rather than site-specific component counts for upstream facilities.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 88

Comment: We would also like to see the final rule expand its coverage to include some additional important leakage areas, such as compressors at well sites and storage vessels.

Response: All equipment located at a well site or compressor station that has fugitive emissions components, as defined within the final rule, is subject to the fugitive emissions monitoring program. See response to DCN EPA-HQ-OAR-2010-0505-6858, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 153

Comment: PA DEP has had a comprehensive permitting program to achieve reductions of air contaminates, including methane, VOCs, and nitrogen oxides, NOx, from sources at natural gas production, compression, processing, and transmission facilities.

The Department's conditional exemption criteria for sources at well sites and general permit for sources of natural gas compression and processing facilities, GP-5, require source owners and operators to comply with stringent requirements, including a leak detention and repair, LDAR program, for any type of leak. PA DEP's LDAR requirements specifically target reduction of methane emissions.

Unlike Pennsylvania LDAR requirements, EPA's proposed LDAR requirements, which apply solely to VOC leaks, would not address methane leaks at dry gas drilling, compression, and processing operations.

Response: The EPA disagrees with the commenter. The final rule requirements apply to fugitive emissions of both methane and VOC. However, the NSPS rule applies only to new, modified or reconstructed affected facilities and would not apply to existing facilities.

Commenter Name: Henri Azibert, Technical Director
Commenter Affiliation: Fluid Sealing Association (FSA)
Document Control Number: EPA-HQ-OAR-2010-0505-6754
Comment Excerpt Number: 11

Comment: In general, FSA members believe that all equipment potentially subject to leaks should be monitored. It is their position that the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites not just to those components that are connected to the fractured, re-fractured or added wells. (Request for comment on page 258).

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 135.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 41

Comment: G. Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

1. Fugitive Emissions From Well Sites

In consideration of the lack of health based setbacks for well sites and that in many cases, sites are located within 1,000, 500 or 300 feet of our homes and schools and even more are located within a mile of our homes and schools; sites where harmful VOCs are emitted daily coupled with the potency of methane emissions to our environment, we recommend that fugitive emissions requirements apply to all fugitive emissions components at modified well sites and those components that are connected to the fractured, re-fractured or added well. We recommend that operators be required to monitor all the components at a well site since the monitoring equipment is already onsite.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 135.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 30

Comment: Should EPA decide to continue with the proposed LDAR requirements, the rule should not be extended to oil wells or facilities that service only oil wells. The PBPA believes the subpart OOOO definition of gas well suffices in distinguishing oil wells from gas wells. The proposed rule is applicable to facilities where high volumes and high pressures are frequently encountered, however, the same is not true for facilities that handle gas solely as a byproduct of oil production.

Should EPA decide to continue with the proposed LDAR requirements, the rule should not be extended to oil wells or facilities that service only oil wells.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 111.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 9

Comment: Additionally, the definition of a well site for this provision of the rule is expansive, and beyond a rational understanding of "site." For example, hydraulically fracturing a well and then including a production system or tank battery that receive the gas/liquids from the well that could be hundreds of feet away in the survey program as a new source does not meet a commonly understood definition of a new or modified wellsite. The addition of a well's production to a tank battery does not increase the number of components or opportunities for leakage at the tank battery or production system, and therefore should not result in requiring surveys beyond the well pad.

Response: We disagree that the addition of a well's production does not increase the number of components. The piping to the tank will include connectors and valves, and may include pressure relief devices or open-ended lines. Therefore, the number of components would increase, and as such there is a greater potential for leaks. See also response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 107.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 28

Comment: Given the above, TXOGA believes that the proposed well site definition is both ambiguous and overly broad, in addition to being unworkable. Indeed, the definition exceeds the authority granted under CAA Section 111 to establish emission standards for new or modified "stationary sources." Accordingly, EPA should narrow, simplify, and clarify the definition to conform to the commonly understood meaning of the term and to be consistent with the meaning of "stationary source" under Section 111 of the Act and the relevant NSPS and permitting regulations. Moreover this definition directly conflicts with the agency's source determination proposal, which includes a geographical restriction on sources for the purposes of aggregation. Indeed, EPA is arguably adopting an approach here that is akin to option 2 in the source determination proposal – the option that it says is not preferred. As discussed below, EPA should be following the well-considered approach under Part 63, Subpart HH.

Specifically, the proposed definition of "well site" is ambiguous and overbroad in that it encompasses not only one or more wells, but also "production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad." As a consequence, the proposed rule envisions a "stationary source" that could encompass a broad and geographically dispersed system of wells and centralized batteries or natural gas treating and processing facilities, whether or not connected by pipeline, provided the collection of sites receives production from such wells. This approach could bring in emission units that are located large distances from the well site and for that reason, is simply unworkable. Moreover, the phrase "one or more areas that are directly disturbed during drilling" introduces significant ambiguity and does not appear to serve any regulatory purpose. It is unclear what the import of "one or more areas" is in the context of a well site, and the reference to drilling activities, which are not regulated or within the scope of EPA's authority since they are not emitting activities, creates additional uncertainty regarding the scope of this definition.

Measured against the statutory and regulatory definitions that have long defined the scope of NSPS requirements, the proposed well site definition fails. It is inconsistent with the statute's definition of "stationary source"—which is "any building, structure, facility, or installation" emitting an NSPS regulated pollutant. It is also inconsistent with how EPA has implemented Part 60. In Section 60.1, the NSPS rules provide that the provisions of this part apply to an "owner or operator of any stationary source *which contains an affected facility*." Section 60.2 defines the *affected facility* to mean, "with reference *to a stationary source*, any apparatus to which a standard is applicable."

Under the statute's definition, *affected facility* cannot be defined more broadly than what could be designated as a single stationary source. This makes sense because Section 60.1(c) ties the stationary source definition to Title V, which limits the major source (which is comprised of stationary sources) to those sources on contiguous or adjacent property. Specifically, Section 60.1(c) provides that in addition to complying with Part 60, an "owner or operator of an affected facility may be required to obtain" a Title V operating permit. This language establishes the tie between Part 60 and Title V's definition, since a source that could not be aggregated for purposes of Title V, clearly cannot be brought into Part 60. In *Summit Petroleum Corp. v. EPA*, the Court rejected EPA's attempt to aggregate physically independent but "interrelated" natural gas sweetening plant and various sour gas production wells commonly owned but separately located within an area of approximately forty-three square miles. The Court held that "EPA's determination that the physical requirement of adjacency can be established through mere functional relatedness is unreasonable and contrary to the plain meaning of the term 'adjacent.'"

The definition of well-site is also inconsistent with the principles established by Congress in Section 112(n) of the Act, which EPA has implemented in 40 C.F.R. Part 63. In CAA Section 112(n)(4), Congress provided:

> (4) Oil and gas wells; pipeline facilities.-
>
> (A) Notwithstanding the provisions of subsection (a) of this section, emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

> (B) The Administrator shall not list oil and gas production wells (with its associated equipment) as an area source category under subsection (c) of this section, except that the Administrator may establish an area source category for oil and gas production wells located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of 1 million, if the Administrator determines that emissions of hazardous air pollutants from such wells present more than a negligible risk of adverse effects to public health.

Under this provision, Congress recognized the unique nature of oil and gas wells and pipeline facilities and sought to prevent in appropriate aggregation of these units. Moreover, Congress directly tied the Section 112 definition to Section 111 providing that the term "stationary source" is to "have the same meaning" as that term has under Section 111 in Section 112(a)(3) and directing EPA to make its list of categories for Section 112 regulation "consistent" with the Section 111 list of source categories to the extent practicable in Section 112(c)(1). Thus, any approach in Section 111 must take into account Congress' direction on the stationary source definition in Section 112 for these operations.

Implementing these mandates, EPA adopted a series of definitions in 40 C.F.R. Part 63. Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities. "Facility" is defined in Section 63.761 as:

> any grouping of equipment where hydrocarbon liquids are processed, upgraded (i.e., remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For the purpose of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment *that is located within the boundaries of an individual surface site as defined in this section*. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. *Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility*. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Section 63.761 defines "surface site" as "any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed."

The EPA developed the proposed definition of facility to (1) identify criteria that define a grouping of emission points that meet the intent of the language contained in section 112(a)(1) of the Act: "* * * located within a contiguous area and under common control, * * *"; and (2) contain terms that are meaningful and easily understood within the regulated industries. . . . Finally, the terms contained in the definition of facility (e.g., surface site and lease) are well understood within the industry and by enforcement agencies....

In addition to the other problems with the definition, the proposed well-site definition is not consistent with the well understood meaning of the term. Based on the above, EPA should correct these shortcomings by defining "well site" (solely for purposes of this regulation) to mean a crude oil and natural gas production facility (defined in § 63.761) that contains one or more wells within the boundaries of an individual surface site as defined in this section. Such an approach would define the affected facility in terms that are meaningful and commonly understood and in a manner consistent with the statutory definition of "stationary source" ("any building, structure, facility, or installation which emits or may emit any air pollutant"). It would also align with the definition of "facility" in the NESHAP standard for the oil and gas source category in Part 63 Subpart HH.

Response: In response to comments that certain terms in the proposed definition for "well site" may be ambiguous, we are further clarifying the boundaries of a well site for purposes of the fugitive monitoring requirements. Our intent is to limit the oil and natural gas production segment up to the point of custody transfer to an oil and natural gas mainline pipeline (including transmission pipelines) or a natural gas processing plant. Therefore, the collection of fugitive emissions components within this boundary are a part of the well site.

However, we reject the other suggestions in the comment on how to define "affected facility" for purposes of the well site fugitive emissions requirements. The intent of fugitive emissions monitoring requirements is to address potential leaking components, that by their nature small, multiple sources of emissions that are disbursed about a facility. We have therefore defined the "affected source" as "the collection fugitive emission components," such as valves, connectors, and flanges that are on production equipment, at a well site. The EPA's definition of "affected facility" in this final rule is consistent equipment leaks standards in other NSPS, which similarly define affected facilities as a collection of leaky components. See, e.g., subpart VVa. The commenter asserts that an "affected facility" must be a single stationary source. By the rationale presented by the commenter, the EPA would need to make each component an affected facility, which would be far more burdensome and unworkable in light of the sheer numbers of leak components. Further, in urging that the "well site" definition in the NSPS comport with the title V "major source" definition, the comment mischaracterizes the relationship between the NSPS and title V applicability. In general, title V applies not just to "major sources," but also to (among other sources) "any other source (including an area source) subject to standards or regulations issued under section [111]." 42 U.S.C. 7661a(a); see also 40 C.F.R. 70.3(a)(2). Thus, while the title V definition of "major source" does require that emitting activities be on "contiguous or adjacent properties," 40 C.F.R. 70.2, the commenter is incorrect in asserting that "a source that could not be aggregated for purposes of Title V [under the major source definition], clearly cannot be brought into Part 60." Title V specifically contemplates that an NSPS source could be subject to title V even if the NSPS source does not meet the definition of a "major source"; the obvious conclusion from that is that an NSPS source can differ from a title V "major source."

The cited rule, 40 C.F.R. 60.1(c), reflects this by noting that the "owner or operator of an affected facility" (i.e. a facility that is subject to an NSPS) "may be required to obtain an operating permit issued to stationary sources." 40 C.F.R. 60.1(c). Contrary to the comment, the rule does not equate an NSPS "affected facility" with a title V "stationary source"; instead it merely notes the potential obligations of the owner/operator and could encompass a situation in which a permitted title V source differed from the NSPS affected facility.

This distinction is also clear in section 502(a) of the CAA, which authorizes the Administrator to exempt source categories from title V applicability if the Administrator finds "that compliance with such requirements is impracticable, infeasible, or unnecessarily burdensome … except that the Administrator may not exempt any major source from such requirements." *Id.* And EPA has done so for affected facilities in the NSPS. 40 C.F.R. 60.5370(c).

The general comment that the statutory terms "stationary source" and "building, structure, facility, or installation" must be defined consistently across Clean Air Act programs is contrary to existing case law. It is well established that the same term in the Act can be given different meanings depending on context. *Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 573-76 (2007) (holding it permissible for EPA to interpret the term "modification" differently in the PSD and NSPS contexts). In fact, *Chevron* itself stated that a "static judicial definition" of "stationary source" was erroneous, *Chevron U.S.A. v. NRDC*, 467 U.S. 837, 842 (1984), and that it was permissible for EPA to interpret the term in light of "the context of [the] particular program" in which it was used, *id.* at 845.

The Chevron Court also, in discussing the four terms "building, structure, facility, or installation," stated: "[I]t would appear that the listing of overlapping, illustrative terms was intended to enlarge, rather than to confine, the scope of the agency's power to regulate particular sources in order to effectuate the policies of the Act, id. at 862 (emphasis added), and "[t]he language may reasonably be interpreted to impose the requirement on any discrete, but integrated, operation which pollutes," id. For the purposes of well site fugitive emission standards, EPA has reasonably interpreted the statutory terms "stationary source" and "building, structure, facility, or installation" to include a collection of fugitive emission components that are on production equipment used at a well site. We believe that this collection of fugitive emission components fits the *Chevron* court's notion of a "discrete, but integrated, operation which pollutes."

The EPA disagrees with the commenter's suggestion that CAA section 112(n)(A) relates to or otherwise affect CAA section 111 in any way. Section 112(n)(A) sets limitations on how to determine a major source of HAP with respect to oil and gas wells for purposes of section 112 (Air Toxics Program). Section 112 requires that standards for major sources of hazardous air pollutant be based on maximum achievable control technology. In explicitly stating in section 112(n)(A) that the provision applies to "any purpose under that section," Congress is clear that it has not extended the provision to any other section of the CAA. Nor is there any reason for such provision to apply to section 111, which makes no distinction between major and non-major sources.

The EPA further rejects the comment urging the EPA to look to the definition of "facility" in the NESHAP part 63, subpart HH for purposes of defining a "well site." First of all, the "facility" definition in 40 CFR § 63.761 is specifically defining a natural gas processing plant, which is very different from an oil or gas well site with respect to its structure and operation. As mentioned above, for example, while all equipment associated with treating and processing gas may be at a single processing plant, wells at different surface sites may share the same production equipment. Secondly, 40 CFR § 63.761 explicitly states that the "facility" definition is for purposes of determining a major source under subpart HH, which imposes the much more stringent MACT standards on majors sources than the standards for area sources that are based on generally available control technology; as mentioned above, the NSPS has no such distinction among sources. In any event, just as the EPA defines "facility" in subpart HH to include the group of equipment used in processing, the EPA similarly defines "well site" to account for all fugitive emissions components on production equipment.

In the context of the major NSR and title V programs, we are promulgating a separate rule today that interprets the statutory terms "stationary source" and "building, structure, facility, or installation," (as well as the title V term "major source") differently (and potentially in a more narrow way) for this source category, due to the context and purposes of those programs. Primarily, the source determination rule is intended to ease implementation of these programs. That objective is consistent with certain of the statutory objectives of those programs. Title V requires EPA to provide "adequate, *streamlined*, and reasonable procedures for *expeditiously*" processing title V permits. 42 U.S. 7661a(b)(5) (emphasis added). The source determination rule is consistent with this, as well as consistent with EPA's authority to exempt certain sources from title V requirements as EPA has done for this source category. Similarly, among the policies set forth by Congress for PSD is "to insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources." 42 U.S.C. 7470(3); cf. *Alabama Power v. Costle*, 636 F.2d at 400-401 (examining purpose stated in section 160(5) and upholding "bubble" approach for PSD). Towards allowing economic growth to occur, Congress set a one-year deadline for action on complete PSD permit applications. 42 U.S.C. 7475(c). The source determination rule is, to use the language of the *Chevron* court, a "reasonable accommodation of conflicting policies" for the major NSR and title V programs. For details please see the RTC for the source determination rule.

The commenter's citation to *Summit Petroleum* is not on point. *Summit Petroleum* concerned EPA's application of the regulatory term "adjacent," which lacked a regulatory definition, to a particular source determination. *Summit Petroleum*, 690 F.3d at 739-40. Thus, what was at stake was EPA's interpretation of its regulation in an adjudication, not EPA's interpretation of the Clean Air Act in a rulemaking:

> Where, as here, we review an agency's interpretation of its own regulation and not its application of a statute passed by Congress, we must defer to the agency's interpretation unless it is "plainly erroneous or inconsistent with the regulation." Auer v. Robbins, 519 U.S. 452, 461, 117 S. Ct. 905, 137 L. Ed. 2d 79 (1997) (internal quotation marks and citations omitted). We afford an agency's interpretation no deference, however, if the language of the regulation is unambiguous, for doing so would "permit the agency, under the guise of interpreting a regulation, to create *de facto* a new regulation." Christensen v. Harris Cnty., 529 U.S. 576, 588, 120 S. Ct. 1655, 146 L. Ed. 2d 621 (2000).

690 F.3d at 740-41. Here, EPA is not interpreting its regulation in the context of a particular source determination. And we are not creating a new regulation under the guise of interpreting an existing regulation, which was the concern of the *Christensen* court. Instead, EPA is through a rulemaking interpreting the statutory terms "stationary source" and "building, structure, facility, or installation" for purposes of the NSPS program. As explained above, this action is governed by the doctrine set forth in *Chevron U.S.A. v. NRDC*. Thus, the analysis by the *Summit Petroleum* Court does not control our action here.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 29

Comment: The proposed rule also solicits comments on whether fugitive emission requirements should apply to all fugitive emission sources at modified well sites (80 Fed. Reg. at 56,638), and modified compressor stations (80 Fed Reg. at 56, 643), or whether the rule should just apply to the fugitive sources connected to the fractured or added well or compressor, respectively. For well sites, fugitive emission requirements should only apply to those components connected to a fractured or added well.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 135.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 32

Comment: EPA also requests comment on (1) "whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well" and (2) "whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor." On the first question, only those components connected to the fractured, refractured, or added well should be subject to the fugitive requirements. ... In addition, EPA has to ensure that it does not sweep in distant sources from the well-site notwithstanding the definition potentially encompassing distant equipment (which we do not believe is authorized).

Response: The EPA disagrees with the commenter. See the response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 135, for information regarding well site modifications. See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45, for information regarding compressor station modifications.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 22

Comment: We are requesting that the definition of an Affected Facility be clarified in the final regulation.

One reader may hold a narrow view of the term and interpret that the definition of an Affected Facility as a result of a new well being drilled at an existing location only covers the new well, piping to the tank battery, and the tank battery.

A different reader may hold a broad view of the term and interpret that the definition of an Affected Facility as a result of a new well being drilled at an existing location to cover the new well, piping to the tank battery, the tank battery, and all other wells producing into the tank battery.

After reading the regulation, we hold the narrow view of the definition, but have shared comments with others involved with our industry that have a broad interpretation of the definition.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 135.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 2

Comment: Does the fugitive monitoring, referenced on page 56638, column 2, under section G. Proposed Standards for Fugitive Emissions from Well Sites and Compressors, require monitoring of valves, connectors, etc. that are in liquid service? (i.e., valves from tanks on loading lines?) These valves are routinely visually inspected and checked for leaks. Lines in low pressure liquid service would be less likely to have methane emissions since the gas would have been separated at that point.

Response: The final rule requires owners and operators to monitor and repair fugitive emissions components (i.e., valves, connectors, PRDs that have the potential to emit VOC or methane) at a well site or compressor station that is subject to fugitive emissions monitoring. Therefore, if valves or connectors in liquid service have the potential to emit fugitive VOC or methane emissions, they would be a part of the collection of fugitive emissions components at a well site or compressor station that is subject to the fugitive emissions monitoring program

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 10

Comment: Fugitive monitoring exempts wells sites that only include well heads, as proposed on page 56611, column 3, under section G. 1. Fugitive Emissions from Oil and Natural Gas Production Well Sites. Does this include well heads with artificial lift (i.e., pump jacks or gas lift)?

Response: The exemption for wellheads from the fugitive emissions monitoring program extends to all wellheads, including those with artificial lift if they are they only equipment at a well site.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 27

Comment: EPA should revise the proposed definition of "fugitive emissions component" to clarify that equipment such as engine crankcase vents, distance pieces, blowdown vents, double block and bleed valves, and lab sample analyzer vents, which are designed to vent under certain conditions, are not covered by LDAR requirements at compressor stations.

Under the proposed NSPS, operators are required to perform surveys of all of the "fugitive emissions components" at a covered compressor station. The proposed definition of "fugitive emissions component" provides that: "Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions." Based on this language, we do not believe that EPA intends for this definition to include equipment such as engine crankcase vents, distance pieces, blowdown vents, double-block and bleed valves, and lab sample analyzer vents, which are all designed to vent under certain conditions. In order to avoid regulatory uncertainty, we ask that EPA clarify in the final rule that none of these types of equipment are covered by the LDAR requirements for fugitive emissions at compressor stations.

In addition, the list of fugitive components in the proposed NSPS would include "any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters." Based on the language in the preamble and text of the proposed NSPS, we do not believe that it is EPA's intention for blowdown vents or thief hatches on tanks to be considered "fugitive emission components" when they are being used for certain operations for which they were designed. Instead, we understand EPA to be focused on ensuring that these components are able to be properly sealed or closed.

It is common in the industry for vessels to be equipped with openings known as "thief hatches" that are used by operators to measure the volume of oil inside the tank before and after transfers to shipping trucks. These and other openings are also used to check for, or repair potential problems with storage vessels. Although the definition of "fugitive emissions component" explicitly references thief hatches, it is our understanding, based on the language in Section 60.5411a(b)(2)-(3) of the proposed NSPS, that EPA only intends to ensure that the openings are properly seated and sealed when these are not open for the reasons enumerated in the regulations. As we understand the proposed NSPS, compressor stations can meet the fugitive emissions requirements by ensuring that the seals on thief hatches do not allow for emissions when the hatch is closed. We do not read the proposed NSPS to prevent operators from opening thief hatches and other tank openings. We believe that this reading is in keeping with both the proposed regulatory text, and EPA's current method of implementing Subpart OOOO. We would also note that many facilities already subject to Subpart OOOO currently use these same tanks and practices. We ask EPA to confirm that this reading is correct, and to add language to the definition of "fugitive emission component" clarifying that opening thief hatches and other openings that are opened for the reasons enumerated in Section 60.5411a(b)(2) are considered "[d]evices that vent as part of normal operations" and are thus exempt from the definition of "fugitive emission component." This definition is necessary to prevent excessive burdens on midstream operators. For properly designed tank systems, EPA should therefore provide an explicit exemption for thief hatches during periods when venting is reasonably required for maintenance, gauging, emergency overpressure relief, or safety of personnel and equipment.

Similarly, EPA should also clarify that "blowdown vents" mean blowdown vents when not blowing down, or provide an explicit exemption for these activities. Additional components that should be removed from the proposed list of fugitive components include closed vent systems, double-block and bleed valves, lab sample analyzer vents, distance pieces, crankcase vents and blowdown vents when blowing down.

EPA should also clarify in the final rule that major equipment such as compressors, separators, pressure vessels, dehydrators and heaters are not fugitive components. EPA should clarify if the intent is to utilize the OGI technology to scan these major pieces of equipment for evidence of leakage above the leak threshold and then tag and repair the area of leakage. If necessary, Method 21 or process knowledge may be used to confirm that the evidence of leakage seen by the OGI technology is actually the regulated pollutant and not thermal differences.

In addition, Closed Vent Systems ("CVS") should be removed from the proposed list of fugitive components. CVS are already regulated under Section 60.482-10 (Standards: Closed vent systems and control devices), and adding them to the list of "fugitive emissions components" will cause unnecessary and duplicative regulation of these systems.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 10. See the preamble section VI.F.2.e for a discussion of the fugitive emissions component definition for compressor stations. We note that certain thief hatches on controlled tanks are included in the definition of fugitive emissions component, as these thief hatches should be part of a closed vent system, and such, there should be no fugitive emissions. We have not clarified what is not a fugitive emission component in the final rule, as it is easier to define what a fugitive emission component is. Owners and operators are only required to monitor components that fall under the definition of fugitive emission component, although we encourage owners and operator to repair leaking equipment that is not subject to the fugitive emission program as expeditiously as possible, as owners and operators have a general duty to minimize emissions.

In the final rule, we have clarified that certain CVS are excluded from the definition of fugitive emission component. However, not all CVS are regulated under other standards, and as such, some CVS are included in the fugitive monitoring program.

Commenter Name: Dan Hannon, Senior Applications Engineer
Commenter Affiliation: Ariel Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6749
Comment Excerpt Number: 5

Comment: 60.5397a: What fugitive emissions…components at a well site and…compressor station?

The topic concerning component leakage measurement by OGI would benefit from a specific notation that reciprocating compressor packing case vents, distance piece vents and crankcase vents are excluded from the OGI "see it and fix it" methodology.

60.5430a What definitions apply to this subpart?

Fugitive Emissions Component: Fugitive Emissions Components have been defined to include distance piece vents and crankcase vents on a reciprocating compressor. If the compressor design includes a distance piece, the vent will capture any leakage that may escape past the packing case final seal (just downstream of the packing seal vent). This leakage should be small, but should be counted among the packing seal leakage. This is not a separate source from the packing seal leakage and should not be included in the definition of a component.

When defined as a component, this allows for OGI to be applied and require the unit to be shutdown. This is not the intent of 60.5385a for packing seal leakage.

If the compressor design does not include a distance piece (smaller compressor models) the small leakage that may escape past the final sealing element will vent through the crankcase.

If the unit is operating on sour gas service, small amounts of clean natural gas can be applied as a purge gas. The purge gas (natural gas) will vent through the distance piece vents and the crankcase vent.

The distance piece vents and crankcase vents on the reciprocating compressor should be removed from the definition of components.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6807, Excerpt 27.

Commenter Name: Henri Azibert, Technical Director
Commenter Affiliation: Fluid Sealing Association (FSA)
Document Control Number: EPA-HQ-OAR-2010-0505-6754
Comment Excerpt Number: 10

Comment: FSA members do recognize that there are pieces of equipment that are very specialized and that may not be able to meet the general guidelines. There should always be an exception for equipment where there is no readily acceptable commercial solution available from typically three different vendors.

Response: We have revised the definition of fugitive emissions component that has removed the equipment types and made definition more specific. We believe that these changes will address the commenters concern on very specialized equipment.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 45

Comment: In consideration of the lack of health based setbacks for compressor stations and that in many cases, sites are located within 1,000 feet of our homes and schools and even more are located within a mile of our homes and schools; facilities where harmful VOCs are emitted daily coupled with the potency of methane emissions to our environment, we recommend that fugitive emissions requirements apply to all of the fugitive emissions sources at the compressor station for modified compressor stations and fugitive sources that are connected to the added compressor. We recommend that operators be required to monitor all the components at a compressor station since the monitoring equipment is already onsite.

Response: We agree with the commenter that when a compressor station is modified, the fugitive emissions program should be triggered for the entire compressor station, although we have clarified our intent as to what constitutes a modification. Because the affected facility is the collection of fugitive emission components at a compressor station and not on a single compressor and the potential emissions of the compressor station would increase, we believe that the modification should trigger fugitive emission monitoring for the entire compressor station. See section VI.F.2.h of the preamble to the final rule for a discussion of this issue.

Commenter Name: Jack Schwaller
Commenter Affiliation: HOERBIGER Corporation of America, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6799
Comment Excerpt Number: 10

Comment: <u>Clarification</u>: Differentiation of *equipment leakage* vs *fugitive emission* for rod packing

1. A rod packing assembly, if not installed properly, can leak gas around the outside of the assembly. Could this be classified as an *equipment leakage* or *fugitive emissions*. We see this often at start-up after the "packings" have been replaced.

Conversely, the inner sealing rings, the rod and the inner assembly contact faces can degrade causing *a leak* due to wear of the "dynamic" seals. This is collected through the case vent line so it is not fugitive. If the leak is excessive and or the vent line is blocked, the gas will divert out the back of the case, but into a cavity that also should connect to the same controlled vent. ***Would this be non-fugitive.***

If in this scenario, this arrangement cannot keep up with a "super leak", then the gas will work its way into the crank case and out its separate vent ***and become fugitive.*** This is extreme however and will not happen in a sites reasonably effective maintenance program. (See note 1)

<u>Recommendation</u>: Both leaks can comingle and not be exactly differentiated, but both leakage problems can be resolved when the assembly is removed and reinstalled (with new seal rings if necessary. Often just a retorquing will resolve the gasket or metal parts leakage if this occurs after a new installation. Also both can be directed out a common vent line. ***Therefore both sources could be grouped as the same type of leak.***

Response: See response for DCN EPA-HQ-OAR-2010-0505-6799, Excerpt 7.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 30

Comment: In the preamble to the proposed NSPS, EPA requested comment on whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations, or just fugitive sources that are connected to the added compressor. EPA notes that, for some modified compressor stations, the added compressor may only be connected to a subset of the fugitive emissions sources on site. Enterprise strongly supports a final rule where the proposed fugitive emission requirements only apply to the subset of sources that are connected to the added compressor.

Given that EPA is promulgating this rule under the *new* source performance standard program, the focus of EPA's regulations should be on the equipment that is actually *new*. By drawing existing, unmodified, equipment at compressor stations within the LDAR program under the broad definition of "modification," EPA risks going beyond its statutory mandate under the Clean Air Act, and instead regulating existing sources under the NSPS program. By applying the new LDAR regulations to only the equipment connected to an added compressor, EPA would limit one of the most expensive compliance requirements included in the proposed NSPS, and prevent the final rule from encompassing unmodified equipment.

Response: See response for DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 3

Comment: As stated in the Proposed Regulation (40 CFR §60.5397(a)), if the fugitive components at a compressor station are "modified", the requirement to monitor leaks, perform repairs and resurvey to confirm that leaks are fixed applies to all sources of fugitive emissions (i.e., the entire compressor station), even if these fugitive components are not new or modified. We certainly do not think EPA intended in this regulation to expand the scope of the fugitive components to cover sources which are not new or modified. As the name implies, the New Source Performance Regulations (NSPS) were developed and have been implemented successfully by EPA for establishing specific emission limits and/or operating requirements for newly installed equipment. These regulations are not designed for, nor should they be used for the purpose of imposing restrictions on equipment at existing facilities. We request that EPA revise the proposed regulation to require leak monitoring and repair only to NSPS applicable fugitive components within a compressor station (equipment that is defined as New or Modified under 40 CFR Part 60).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.

Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 13

Comment: In addition, the rule should clarify that if a storage compressor station triggers the NSPS, leak monitoring and repair requirements apply only to NSPS applicable fugitive components within a compressor station (equipment that is defined as New or Modified under 40 CFR Part 60) rather than to the entire storage field.

Response: Owners and operators are only required to monitor components that fall under the definition of fugitive emission component, although we encourage owners and operator to repair leaking equipment that is not subject to the fugitive emission program as expeditiously as possible, as owners and operators have a general duty to minimize emissions.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 72

Comment: Additionally, EPA requests comment on "whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just fugitive sources that are connected to the added or modified compressor." In response to this request, Kinder Morgan comments that the fugitive emissions requirements should apply only to the fugitive sources that are connected to the new or modified compressor. This approach is consistent with how other "affected facilities" are identified in §60.5365a (e.g., each reciprocating compressor is an affected facility per §60.5365a(c) and each centrifugal compressor with wet seals is an affected facility per §60.5365a(b)). To subject all of the fugitive emissions sources at the compressor station to additional requirements would be immensely over-burdensome, costly, unnecessary, and not supported by adequate data. Furthermore, EPA did not conduct a cost analysis to demonstrate the effectiveness of imposing such expansive requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45. The cost analysis for the fugitive monitoring requirements can be found in the TSD for the final rule.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 30

Comment: The proposed rule also solicits comments on whether fugitive emission requirements should apply to all fugitive emission sources at modified well sites (80 Fed. Reg. at 56,638), and modified compressor stations (80 Fed Reg. at 56, 643), or whether the rule should just apply to the fugitive sources connected to the fractured or added well or compressor, respectively. ... For compressor stations, fugitive emission requirements should only apply to those components connected to the added compressor.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 33

Comment: EPA also requests comment on (1) "whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well" and (2) "whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor." On the second question, the requirements should only apply to the fugitive sources connected to the added compressor.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45.

Commenter Name: Lee Fuller, Executive Vice President, and V. Bruce Thompson, President
Commenter Affiliation: Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6983
Comment Excerpt Number: 20

Comment: E. Compressors

Similarly, IPAA/AXPC requests clarification on whether compressors at well sites are subject to LDAR requirements. Finally, in response to EPA's specific request, IPAA/AXPC suggests the fugitive emissions requirements at compressor stations should apply only to the fugitive sources that are connected to the added or modified compressor.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 5

Comment: EPA Should Amend the Definition of "Modification" to Exclude Changes that do not Result in Emissions and Should Amend the Definition of Fugitive Methane at "Affected Facility" to cover only those Parts of a Compressor Station Actually Affected by a Modification.

With respect to the control of fugitive methane emissions, EPA proposes to define "modification" such that any addition of a new compressor or compression capacity triggers the fugitive emission control requirements at the compressor station "affected facility." Furthermore, EPA proposes to define the "affected facility" in this context as the entire compressor station. Both of these approaches are overbroad and exceed EPA's statutory authority. EPA's expansive definition of what entails a "modification" at an existing compressor station could affect many thousands of parts and components at existing compressor stations. Therefore, the impact of the Proposed Rule is significantly more expansive for the T&S sector than EPA acknowledges.

EPA may not presume that all additions of compression are "modifications" because not all additions of compressors increase fugitive emissions at a compressor station.

EPA proposes, for purposes of the fugitive emissions methane standard for compressor stations, that a "modification" to a station occurs any time that: (1) a new compressor is constructed at an existing compressor station; or (2) a physical change is made to an existing compressor at a compressor station that increases the compression capacity of compressor station. This definition incorporates the concept of a physical change to a part of the station but omits an explicit demonstration that these changes result in an increase in emissions.

However, CAA § 111 defines "modification" in terms of both a change and a resulting emissions increase. Specifically, it defines the "modification" of a source as a physical or operational change that "increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." In addition, EPA's own general regulations interpreting section 111 define "modification" to occur only when there is a physical or operational change and an increase in the source's emissions rate.

Therefore, EPA's definition of "modification" for purposes of the proposed fugitive emission standards is not consistent with the Agency's statutory authority as the Agency has not provided a reasoned basis for presuming that any addition of compression at a compressor station necessarily increases fugitive emissions at the station.

In fact, there are many instances in which the addition of a compressor or compression capacity at a compressor station does not result in an increase in fugitive emissions (or the rate of such emissions) at the station. For example, the addition of a new compressor at an existing facility may replace other units, and a single, larger unit may replace multiple smaller units. In these instances, emissions may actually decrease from newer equipment or from fewer components that have the potential to leak. Similarly, horsepower replacement or upgrades do not necessarily cause increased fugitive emissions.

For these reasons, we urge EPA to more narrowly and precisely define "modification" in the context of fugitive emissions at a compressor station so it covers only those additions of compressors or compression capacity that increase the rate of fugitive emissions of the station.

To this end, INGAA supports the American Gas Association's recommendations for changes to the regulatory definition of "modification."

EPA should affirm the NSPS exemptions for routine maintenance, repair and replacement.

We request that EPA affirm that the exemptions in the general NSPS regulations remain available for fugitive emission components at compressor stations, including the exemption for physical or operational changes that constitute routine maintenance, repair and replacement. These exemptions are important to provide certainty to operators of compressor stations that undertake such activities as the like-kind replacement of an old compressor with a new compressor. Such activities should not trigger "modifications" under the OOOOa Rule.

EPA's definition of the fugitive methane "affected facility" unreasonably presumes that any addition of compression increases fugitive emissions throughout the entirety of a compressor station.

To be sure, there are cases in which the addition of compression at a compressor station can increase fugitive methane emissions. However, as explained below, the Proposed Rule unreasonably presumes that in all such cases the potential for fugitive methane emissions increases throughout the entire compressor station. EPA has appropriately solicited comment on the validity of this presumption.

EPA has proposed to define, for purposes of the fugitive methane emissions standard, the "affected facility" as the "collection of fugitive emissions components" at a compressor station. EPA further proposes to define "fugitive emission component" as "any component that has the potential to emit fugitive emissions of methane… at a compressor site."

The implication of these proposed definitions is that any addition of compression to any part of a compressor station is not only presumed to increase fugitive methane emissions (as discussed above), but moreover is presumed to increase these emission throughout the entire station – thereby triggering the requirement to apply the work practice standard for fugitive emissions at every one of the thousands of "fugitive emission components" in the station.

In the preamble, EPA acknowledges that "for some modified compressor stations, the added compressor may only be connected to a subset of the fugitive emissions sources on the site" – and therefore solicits comment on whether the abatement requirements should only apply to the subset of components actually affected.

There are cases in which the addition of a compressor at a compressor station will increase throughput at only part of the station rather than the whole station—which means that the potential for an increase in fugitive emissions is confined just to the affected part. For example, a new compressor could be installed adjacent to existing compressors where the new compressor piping is connected directly into the existing compressor piping manifolds. A fugitive emissions increase would result from addition of valves and other components associated with the new compressor, but it would not increase the fugitive emissions from the existing compression manifold piping. Another example could be the addition of a new compressor in a new building at an existing compressor station. A fugitive emissions increase would result from the installation of the piping and components for the new compressor building into the existing station piping or mainline pipeline. However, fugitive emissions from the existing compressors and associated piping and components would not be increased.

For these reasons, INGAA urges EPA to define “affected facility” as the portion of a compressor station at which fugitive methane emissions increase as the result of a “modification.” This change is necessary to ensure that the operator of a compressor station need only apply the fugitive emission abatement requirements at the portion of a station actually affected by the addition of a compressor or compression capacity.

Response: The EPA agrees with the commenter that the definition of a modification to a compressor station should be amended. We have revised the definition of modification to address the issues raised by the commenter. See section VI.F.2.h of the preamble to the final rule. See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 45, for information regarding requirements for fugitive monitoring surveys.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 8

Comment: EPA Must Provide Appropriate Limits on the Definition of “Compressor”

EPA fails in the proposed rule to provide a definition for the term “compressor.” Compressors play a central role in this proposed rule and, as a result, it is important that EPA clarify which types of compressors are at issue here. For example, EPA’s proposed definition of modification is based on the addition or physical change in a compressor. See 40 C.F.R. § 60.5362a(j). Unless EPA defines compressor, owners and operators will face uncertainty as to the types of compressors that are covered by the proposed fugitive emissions monitoring regulations. GPA proposes that EPA define compressors for purposes of fugitive emissions monitoring as Subpart OOOOa-applicable reciprocating compressors and Subpart OOOOa applicable centrifugal compressors. This is consistent with other provisions in Subpart OOOOa where EPA places requirements on both centrifugal and reciprocating compressors, while avoiding obligations on any other types of compressors such as vapor recovery unit compressors that are installed to recover methane and VOC emissions. This clarification will eliminate potential applicability confusion down the road for sites with other types of compressors. Also, in accordance with 40 C.F.R. § 60.14(e)(6), the relocation of an existing facility, by itself, shall not constitute a modification. Without defining “new compressor” as one subject to Subpart OOOOa, the relocation of an existing compressor from one facility to another could trigger modification of the compressor station affected facility which is in direct conflict with 40 C.F.R. § 60.14. GPA proposes to add following provision to EPA’s proposed regulations:

40 C.F.R. § 60.5365a(j)(3): For purposes of defining a compressor station affected facility under this subsection, compressor means a centrifugal or reciprocating compressor that moves natural gas at increased pressure through gathering or transmission pipelines. A Vapor Recovery Unit (VRU) compressor used to recover vapors from a storage tank, separator, or other equipment is not a new compressor for purposes of this subpart.

Response: The EPA believes the definitions and requirements in the final rule reflect the intent in regards to compressor stations and does not believe additional definitions are required. We note that compressors located at well sites or onshore natural gas processing plants are not considered to be compressor stations for the purposes of fugitive emissions monitoring.

See the response to DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 5 for more information concerning modifications to compressor stations.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 9

Comment: EPA Must Provide Appropriate Limits on the Definition of "Compressor Station Site"

EPA's proposed definition of "compressor station site" is overly broad and could result in an inadvertent overlap between sources regulated under the NSPS program as compression station sites and those regulated as gas processing plants. As proposed, "[c]ompressor station site means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations." Proposed 40 C.F.R. § 60.5430a. GPA is concerned that this proposed definition could be interpreted to include compression at a natural gas processing plant. This would create uncertainty as to whether such compressors should be regulated as a compressor station site, as part of the gas processing plant, or both for purposes of the NSPS program.

To avoid any overlap in the way that gas processing plants are regulated under the NSPS program, GPA requests that EPA limit the definition of compressor station sites to sites located "prior to the inlet of a natural gas processing plant." This will clarify that fugitive emissions regulations imposed under Subpart OOOOa will apply only to compressor stations associated with gathering lines.

To further avoid confusion, GPA urges EPA to explicitly exclude transmission stations and storage facilities from the definition of compressor station sites. This will further avoid confusion about the downstream limits of compressor station sites and ensure that natural gas processing plants are excluded. To the extent that EPA believes it is necessary to define and regulate compressors associated with transmission lines and storage facilities, GPA urges EPA to separately define and regulate those sources. Because gathering and transmissions lines and storage facilities are fundamentally different parts of the natural gas supply chain, it is neither necessary nor advisable to regulate them together under a single definition of compressor station site. Thus, to properly reflect their different roles and operations, GPA urges EPA to adopt definitions that clearly distinguish between compressors associated with gathering, processing, transmission, and storage.

Thus, the definition of compressor station site should be "any permanent combination of one or more compressors that move natural gas at increased pressure through gathering ~~or transmission~~ pipelines~~, or into or out of storage~~, **<u>prior to the inlet of a natural gas processing plant</u>**." Revising this language in the definition of compressor station site will avoid uncertainty by clarifying that compressors located at gas plants are considered to be a part of the gas processing plant, and do not meet the definition of a compressor station site, removing any potential overlap in LDAR requirements.

Response: The EPA has modified the definition of "compressor station" to state that compressors located at onshore natural gas processing plants are not a compressor station for the purposes of fugitive emissions monitoring. We believe that this removes any confusion as to which fugitive emissions requirements apply to different pieces of equipment. We have not exempted compressors associated with transmission and storage in the definition of compressor station, as transmission and storage are a part of the source category. We also do not see a need to regulate compressor stations differently at transmission and storage facilities nor do we have information on how we would do so.

Commenter Name: Laura K. Perry, Coordinator - Air Quality
Commenter Affiliation: ConocoPhillips Alaska, Inc. (CPAI)
Document Control Number: EPA-HQ-OAR-2010-0505-6947
Comment Excerpt Number: 6

Comment: It is not entirely clear how broadly EPA intends the phrase "compressor station site" to be applied but, as defined in proposed OOOOa, it could be applied in a manner that could cause oil production facilities to be included (these compress gas for reinjection into reservoirs). We don't think this is the intent. As such, we propose the definition be amended to make it consistent with the definition of "onshore natural gas transmission" found at 40 CFR 98.230(a)(4) as follows:

[Note: Underlined text below indicates commenter's suggested language additions.]

> *"<u>Compressor station site</u> means any permanent <u>facility whose primary function is to compress and move gas at increased pressure via a</u> combination of one or more compressors ~~that move natural gas at increased pressure~~ <u>out of a production field, out of a natural gas processing plant, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage.</u> ~~through gathering or~~*

~~*transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations, and transmission compressor stations.*~~"

Similarly, use of phrases like "gathering and boosting station" and "transmission compressor station" without definition will cause uneven application of the rules.

Response: The EPA has amended the final definition of compressor station to indicate that a compressor located at a well site or natural gas processing plant is not a compressor station for the purposes of fugitive emissions monitoring. We believe this revision addresses the commenter's concern.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 14

Comment: We also seek confirmation from EPA that the proposed regulation does not apply to LNG facilities as they do not belong to the source categories covered in the regulation.

A liquefied natural gas (LNG) facility is defined in the existing NSPS standards promulgated in August 2012 (Quad O) and the proposed regulation (Quad Oa). However, there are no applicable requirements specified for the emission sources at the LNG facility. We support EPA's interpretation to not subject LNG facilities to the requirements of the proposed regulation. We request EPA's concurrence regarding the non-applicability of the proposed regulation to an LNG facility. If EPA intends to include LNG facilities, the rule should clarify that if an LNG facility triggers the NSPS, leak monitoring and repair requirements apply only to NSPS applicable fugitive components within the compressor station (equipment that is defined as New or Modified under 40 CFR Part 60) rather than to the entire LNG facility.

A compressor station is defined in the rule as:

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

In some instances, LNG facilities include compressors which are intended to move natural gas from there-boilers into transmission pipelines or storage within the facility. However, they are located within the boundaries of the LNG facility. Under the current draft rule, if additional compression is added to the LNG facility, the leak monitoring and repair requirements are potentially applicable to the fugitive components at the entire facility, which is clearly beyond the boundary of a common sense definition of a "compressor station."

Response: We have revised the definition of a compressor station to exclude compressors located at a well site, or located at an onshore natural gas processing plant. Per §5365a(f)(2), equipment associated with a liquefied natural gas facility is covered by certain sections of the final rule if the liquefied natural gas facility is located at an onshore natural gas processing plant. Equipment associated with a liquefied natural gas facility not located at the onshore natural gas processing plant site is exempt from the fugitive emission provisions.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 13

Comment: A central feature of the proposed new Subpart OOOOa requirements is a wide-ranging program requiring survey and repair of fugitive emission sources at compressor stations. As discussed below, TPA believes that EPA's proposed approach to regulation of compressor station fugitive emissions would create onerous requirements on the natural gas industry given the unique characteristics of compressor stations. We propose an alternative approach, based on initial site screening that would target sources that are responsible for a disproportionate share of fugitive emissions. In the event that EPA decides to retain its currently proposed approach, however, we also offer our comments and proposed revisions that would improve the requirements that EPA is currently proposing.

Proposed new Subpart OOOOa would impose new rules that would require owners and operators to find and repair sources of fugitive emissions at compressor stations throughout the oil and natural gas source category and that would also impose extensive recordkeeping and reporting requirements. TPA's overarching concern is that the fugitive emissions program that EPA is proposing is simply not suited to compressor stations. EPA proposes to impose "big plant" requirements on what are often small, unmanned, and/or remote facilities. EPA's proposed program is more suited for facilities that are large, manned, and located at one centralized location, such as refineries, rather than multiple, small, dispersed sources. Compressor stations are very prevalent in the oil and gas industry -much more so than refineries (fewer than 150) and processing plants (approximately 500). A recent study estimated that there are approximately 4,549 gathering facilities in the United States (which almost always have at least one compressor station and normally have more than one compressor station), and a separate study estimated that there are over 1,500 compressor stations in the domestic transmission segment alone. The large number of compressor stations in the country is also demonstrated by EPA's Technical Support Document in this rulemaking, which puts the number of gathering compressors at over 36,000 - just in the gathering and boosting industry segment.

The sort of comprehensive, component-by-component survey, repair, resurvey, and documentation/reporting regimen that EPA is proposing - including minutiae down to a requirement to detail the defined survey path - is simply not suited to compressor stations. EPA's failure to appreciate this distinction has led it to apply numerous onerous requirements that are more suited for large, complex, centrally located industrial facilities than for the numerous small, remote, and possibly unmanned compressor stations in the oil and gas industry, and those requirements would impose a completely unreasonable burden on owners and operators of compressor stations.

Response: The data available to the EPA regarding compressor stations indicates that they can be a significant source of fugitive methane emissions. Therefore, we have included requirements for fugitive monitoring consistent with the BSER analysis finding that application of the quarterly monitoring requirements is reasonable based on estimated emission reductions. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

We have made numerous requirements to the final rule based upon comments received. See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22, for information on changes made to accommodate small business. See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29, for information related to recordkeeping and reporting.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 8

Comment: Data from Chevron's existing leak detection/find and fix programs indicates that leaks are concentrated at compressors and vapor recovery units, with minimal leaks at wellhead. It will be more cost effective to focus the scope of requirements to surveys only on sites with compressors or vapor recovery units.

Response: The EPA notes that well sites that only contain wellheads are not affected facilities for the purposes of fugitive emissions monitoring.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 19

Comment: EPA Should Clarify Its Intention to Regulate Compressor Stations Associated with "Underground" Storage.

The proposed rule defines "compressor station site" to include "compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage." Because "storage" is not defined, the proposed rule could impose fugitive emissions requirements not just on compressor stations used to move natural gas into or out of underground storage, but also compressor stations at liquefied natural gas (LNG) storage and propane storage for peak shaving facilities. Because there is no justification or cost-benefit analysis for the inclusion of LNG or propane storage for peak shaving facilities, AGA encourages EPA to revise the definition of "compressor station site" to clarify that storage is limited to underground storage.

EPA has made no indication that it intends to regulate compressor stations at LNG and propane storage facilities. The proposed rule, including EPA's supporting analysis, is virtually silent on what the Agency means by "storage." However, if EPA had intended to include LNG and propane storage facilities, a broader set of data, including the cost imposed on peak-shaving facilities, would be necessary to support including the compressors stations located at the nearly 75 LNG peak shaving facilities located in the U.S. This conclusion is supported by EPA's website, which describes natural gas transmission and storage to include (1) transmission and compressor stations; (2) transmission pipeline; and (3) underground storage.

Furthermore, there is no environmental benefit for including these facilities. The Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration subjects LNG storage facilities to stringent regulations requiring the performance of leak surveys and permanent repairs for safety concerns. Under 49 CFR Part 193, LNG storage terminals are required to install leak and flammable gas detection systems, to monitor those systems continuously, and to repair any leaking or defective component. These requirements will likely identify and address any fugitive emissions before they would be identified through the proposed LDAR for fugitive emissions at compressor stations. As a result, the negligible fugitive emissions associated with these compressor stations do not warrant the increased regulatory burden of subjecting these facilities to the proposed NSPS. The minimal amount of fugitive emissions from LNG storage facilities is supported through the GHGRP data. In both 2013 and 2014, only 5 of the nearly 75 LNG storage facilities in the U.S. reported under the GHGRP, suggesting that nearly all of these facilities do not meet the 25,000 CO_2e reporting threshold, even including CO_2 from combustion emissions as well as their minimal fugitive methane emissions.

To ensure that LNG and propane peak shaving storage facilities are not unnecessarily included in the proposed rule, AGA encourages EPA to revise the definition of compressor station site as follows:

Compressor station site means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of <u>underground</u> storage<u>, as defined in 40 C.F.R. §98.230(a)(5), on a natural gas transmission line</u>. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations.

By making this revision, EPA will ensure that compressor stations at LNG and propane peak shaving storage facilities are not unintentionally regulated.

Response: The EPA disagrees with the commenter that the EPA should revise the definition of a compressor station to specifically refer to underground storage. The commenter's question appears to be more a reflection of whether the facilities for storage of LNG and propane peak shaving storage are considered to be part of the natural gas transmission and storage segment. If these facilities are in the natural gas transmission and storage segment, then the compressor stations would be covered by the rule. If these facilities are in the distribution segment, then the compressor stations are not covered by the final rule.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)
Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 14

Comment: LDAR survey program should not be based on component count or percentage of components leaking program

EPA's current proposal incorrectly bases its LDAR survey program on an arbitrary component count or percentage of components leaking methodology to incentivize a company's vigilance in leak identification and repair. Companies with a high number of components—sometimes in the thousands or tens of thousands—would face prohibitive costs in monitoring and maintaining records under a component count LDAR survey program. Additional unforeseen and unaccounted for costs exist as well, including those related to training, data management, and set-up. Finally, all components are not equal. Experience in states with strict LDAR programs indicates that treating every component as equal is ineffective in a survey or monitoring program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 22

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 19

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 20

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 20

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 21

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 19

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 20

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 20

Comment: EPA's analysis also does not establish differing compliance or reporting requirements or timetables that take into account the resources available to small entities. EPA has attempted to take into account the fact that small E&P entities are more likely to drill smaller wells, which will produce fewer barrels per day than the wells drilled by bigger entities. While EPA provides an exemption for fugitive monitoring requirements for well sites that average below 15 barrels of oil equivalent per day ("boepd"), this exemption will not provide any actual relief to small entities. First, it would be difficult, if not impossible, for a well site averaging below 15 boepd to be profitable. As a result, few, if any, small entities will attempt to operate new well sites that average 15 boepd.

In addition, small entities are unlikely to know their actual average boepd until after they have already expended the resources to complete those wells. This after-the-fact exemption is little help for companies like Trilogy, because they must estimate their compliance costs at the outset of the project to determine whether it is economically feasible to drill, fracture, or refracture a well. Given the short timeframe that EPA gives these entities to perform fugitive monitoring after a start-up or modification, small entities must make decisions about whether to hire additional personnel, or invest in Optical Gas Imaging ("OGI") cameras, before drilling or modifying a well site. As a result, this exemption for low-producing wells does not provide relief for small entities, and demonstrates a misunderstanding of the upstream industry. Small entities will have to spend the capital to comply with these rules before they are in a position to determine whether compliance is even required. Instead, EPA should provide an exemption either for all small entities, or based on the total number of affected wells at a particular well site to provide greater clarity and certainty to small entities when they make a decision about whether or not to drill a new well, or fracture or refracture an existing well.

Response: The final rule does not include an exemption from the fugitive emissions monitoring provisions for low production well sites. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Because of the prevalence of such well sites and in the absence of data showing that equipment counts or fugitive emissions are lower at low production well sites, we decided not to exempt low production well sites from the fugitive emissions monitoring program in the final rule, as we believe that the emissions from low production and non-low production well sites are comparable. In addition, some commenters indicated that such an exemption would not provide relief to small entities. See section VI.F.1.b of the preamble for more information regarding this issue.

Changes to the rule from proposal that may benefit small entities include allowing both OGI and Method 21 as acceptable monitoring technology; replacing a performance based monitoring schedule with a fixed frequency; lengthening the time of initial fugitive monitoring from within 30 days to either one year after the date of publication of the final rule in the Federal Register or within 60 days of the startup of production, whichever is later; increasing the time for components with fugitive emissions to be repaired and resurveyed and simplifying the third party verification of technical infeasibility requirements. Though these are not monetized, we believe the flexibility and simplifications these changes have added to the rule result in a reduced burden on small entities. See section X.C of the preamble for more information regarding the consideration of impacts on small entities. See sections VI.F.1 and VI.F.2 of the preamble for a complete discussion on changes to the fugitive emissions program.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 33

Comment: EPA's Proposal to Exempt Wells Producing Less than 15 Barrels of Oil Equivalent Per Day is Arbitrary and Not Supported by the Record.

EPA has proposed to exclude from LDAR requirements wells that produce less than 15 BOE/d in the first month of production, which the agency considers low- producing wells. 80 Fed. Reg. at 56,639. This exclusion is arbitrary, lacks a rational explanation, and is not supported by the record.

EPA justifies this exemption on the grounds that "emissions at low producing wells are inherently low," "such well sites are generally owned and operated by small businesses," and LDAR requirements at these facilities could therefore impose hardship on small businesses. *Id.* The agency provides no evidence to support these assertions, though requests comment on each, including comment on different thresholds or other policy approaches that could secure reductions at these sites. *Id.* Below, we include a table setting forth our analysis of new and existing wells that would be affected by this exemption. We also provide evidence demonstrating that each of the agency's three fundamental assumptions is flawed, then offer recommend improvements to EPA's proposed exclusion to ensure application of LDAR at these wells.

Lower Producing Wells Can Have Substantial Emissions. EPA sets forth its understanding that lower producing wells are "inherently" low-emitting, yet the Agency provides no evidence to support this assertion. In fact, there is some connection between production level and emissions—indeed, production levels serve as a cap on potential emissions. However, differences in production levels explain only a small portion of the differences in emissions among sites. Table 2 below provides a breakdown of the new well completions and emissions from new wells associated with the 15 BOE/d threshold for both oil and gas wells. As is illustrated, 24 percent of all new well completions, and 20 percent of the total emissions associated with those wells, are excluded under the 15 BOE/d threshold and thus would be exempt from all Federal fugitive standards. Further, if both new and existing wells are considered, 76 percent of total wells and total emissions are excluded under the 15 BOE/d threshold.

[Table 2: new Well Counts and Emissions, shows distribution of wells >15 BOED and <+ 15 BOED for gas and oil wells with % breakdown of those between those values.]

Published research shows that these low producing wells can be responsible for substantial emissions. Zavala-Araiza, et al. performed an analysis illustrating how the probability of a production site being among the highest emitting sites does not increase uniformly with production volume. Consequently, requiring LDAR only at sites above certain production levels would exempt sites with low production but potentially high fugitive emissions. The analysis performed by Zavala-Araiza, et al. identified significant emission reduction opportunities for the lower production cohorts. In this analysis, production sites in the Barnett Shale production region of Texas were classified into four production cohorts, with the two lower ones including wells that produce less than 10 Mcf/day and 10 to 100 Mcf/day, respectively. (For reference, 15 BOE/d is equal to roughly 87 Mcf/day.) These two cohorts accounted for 33 percent of total Barnett Shale emissions, with 76 percent of total emissions from these cohorts attributed to functional super emitters (defined here as sites with an excess of emissions related to avoidable operating conditions).

The study reports measurements from a total of 75 wells (65 production sites) that would fall below the production threshold of less than 15 BOE/d. The average emission rate from these sites is 1.90 kg CH_4/h (18.4 short tons CH_4/ year), and 30 percent were classified as functional super-emitters, where their emissions represented between 1 percent and 100 percent of their production. The average rate from these facilities is higher than the central emission factor derived for all production cohorts by Zavala-Araiza, et al., which was 1.03 kg CH_4/h per production site (9.95 short tons/year). It is also far higher than EPA's projection of emissions from a model well site, which the agency estimated to be about 4.4 tons per year.

[Figure 3: Proportional Loss Rate (emission as a percent of produced gas) Versus Absolute Methane Emissions (tons methane per year) for Wells Producing less than 15 BOE/d]

The results presented by Zavala-Araiza, et al. show that lower producing wells can have significant emissions. Based on the high proportional loss rates at those sites, LDAR could significantly reduce fugitive emissions at these facilities Figure 3 above shows measured production sites where production per well was less than 15 BOE/d. The x-axis shows absolute methane emissions in short tons per year, while the y-axis shows proportional loss rate (methane emissions divided by methane production). Red dots correspond to sites classified as functional super-emitters (Zavala-Araiza, et al.), meaning their emissions represent 1 percent to 100 percent of their production. The black dotted line represents the average emission factor determined by Zavala-Araiza, et al. for all the production sites (all production levels) in the Barnett Shale. The figure shows that many of the sites with production less than 15 BOE/d are classified as super-emitters and are, contrary to EPA's assumptions, associated with high absolute emissions. Clearly, with high emissions (12 of the well sites are classified as functional super-emitters and emit *over 5% of production*, an instrumental leak detection and repair program, such as with OGI, can readily reduce emissions from these sites.

[Figure 4: Proportional Loss Rate (emissions as a percent of produced gas) Versus Absolute Methane Emissions (tons per year) for Facilities and Functional Super-Emitters in Various Production Categories]

Figure 4 above also illustrates the distribution of super-emitters relative to production. As indicated, functional super-emitters are distributed across all production tiers, indicating no direct correlation between production and absolute emissions or between production and proportional loss rate. In fact, sites producing less than 5 BOE/d – much less than EPA's proposed threshold of 15 BOE/d – are some of the highest emitters in both percentage terms *and absolute terms*.

Policy Recommendations. Given the potentially significant emissions from these sources, we recommend that EPA eliminate the 15 BOE/d exclusion. As shown above, these smaller producing wells can be the source of very harmful emissions. If EPA concludes that LDAR inspections, at the frequency generally applied to well sites (i.e., semi-annual in EPA's Proposal, or quarterly as we show would be justified, below) is not appropriate for lower emitting wells, EPA should apply less frequent monitoring requirements to these wells instead of exempting them entirely. To the extent EPA moves forward with tiered monitoring requirements (which we address more fully below), such tiering could help to ensure these lower producing wells do, in fact, perform, LDAR. In the Colorado regime, for instance, even the smallest wells are required to perform LDAR, and EPA should at least apply a similarly calibrated approach.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: I. Snow
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5411
Comment Excerpt Number: 3

Comment: Similarly, the rule does not include low production well sites. This should be amended as well. Though 15 barrels per day or less is certainly low compared to large operations, the combination of many of these sites operating 365 days per year is still a mathematically significant amount. For the same reason as existing sources, these sites need to be monitored, even if only annually, as smaller operations may have less means to conduct frequent surveys. Or perhaps include a designation for regulating these sites based on the business' financial ability or size, but they should not be left unconsidered.

If one goal of the rule is creating climate benefits (as the only benefit actually monetized in the document), the standards need to include existing and low production sources as well, in order to make any significant progress towards that goal and maximize those benefits.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 43

Comment: We caution the EPA to be very aware that with numerous multi-well sites located near, within measurable feet from our homes and schools, it is necessary that prudent consideration be given to any exclusionary provisions. Regardless of a particular low production well's fugitive emissions, it is still a part of the cumulative fugitive emissions we are experiencing near our homes and schools. Fugitive emissions such as harmful VOCs and potent methane must not be given a free pass because they are emitted at a low production well. Given the fact that well pad setbacks are not determined from health-based standards we do not recommend any exclusion from the proposed rules.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 19

Comment: Regarding low production facilities, referenced on page 56664, column 3, under §60.5365a (i)(1), the rule should be changed to <15 boe/day over 30 days production instead of "the first 30 days of production" this would allow low production sites to roll out of applicability and focus resources on sites that should be surveyed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 13

Comment: The MSC recommends U.S. EPA modify the 15 BOE/day low-production exemption to also consider this an off ramp to be applied at any time during the life of the well. As soon as a well drops below this threshold it should immediately be considered an exempt facility. Additionally, the MSC recommends the incorporation of a well-site exemption for facilities with a gas-to-oil ratio of equal to, or less than, 300 scf/bbl.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 105.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 29

Comment: PIOGA generally supports the exclusion of "low production well sites" from the fugitive emissions provisions of Subpart OOOOa.

Regardless of the averaging period selected by EPA, the regulations should clarify that the 15 boe also acts as an "off ramp" regarding the fugitive emission requirements – when a well drops below the boe on a 30 day average, the well is relieved of the LDAR monitoring requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: J. Roger Kelley, Director, Regulatory Affairs
Commenter Affiliation: Continental Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6963
Comment Excerpt Number: 15

Comment: Wells with Production Less than 15 boe/d or 90 mscf Should Be Excluded from the LDAR Requirement.

Excluding low production well sites from the LDAR requirement makes sense from both an environmental and economic perspective. Fugitive emissions from such wells are a mere fraction of the already commendable and continually decreasing levels of emissions associated with typical wells drilled and completed using today's technologies, for which initial production rates typically average between 500 and 1,000 boe/d. Therefore, neither the perceived environmental benefits nor the true and significant costs, in terms of dollars per ton of emissions avoided, can justify application of the LDAR requirement to low production wells.

Continental supports the limited LDAR exclusion EPA has proposed but requests it be expanded. Specifically, Continental believes a low production well, to which the LDAR requirement does not apply, should be defined as a well which produces less than 50 barrels of oil equivalent per day (boe/d) — not EPA's current threshold of 15 boe/d. Furthermore, the LDAR exclusion should apply not only to a well which produces less than 50 boe/d during its first 30 days of production but to any well whose production subsequently declines such that the 30-day average daily production of the well during any given period is less than 50 boe/d.

Alternatively, EPA's low production well definition should be modified to reflect more precisely EPA's cited definition of a stripper or low production well, which appears in Section 613 of the Internal Revenue Code ("RC"). EPA justifies its 15 boe/d definition of a low production well by citing IRC Section 613, but a closer reading of Section 613 indicates a stripper or low production well is defined as (i) an oil well that averages less than 15 barrels of oil per day or (ii) a gas well that makes less than 90 mscf per day. Therefore, it would be more appropriate for EPA to clarify the LDAR requirement will not apply *either* to an oil well that averages less than 15 barrels of oil per day *or* to a gas well that makes less than 90 mscf per day. Finally, EPA should clarify that a well once subject to the LDAR requirement based on its first 30 days of production will no longer be subject to the LDAR requirement if its 30-day average of daily production at any point falls below 15 barrels of oil per day (for an oil well) or 90 mscf per day (for a gas well).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Morgan Lambert, Deputy Air Pollution Control Officer
Commenter Affiliation: San Joaquin Valley Air Pollution Control District in California
Document Control Number: EPA-HQ-OAR-2010-0505-6974
Comment Excerpt Number: 8

Comment: Notwithstanding the above, in order to avoid duplicative control measures that will not result in any additional emissions reductions the District supports EPA consideration of the efficacy versus expense of subjecting low production wells to additional LDAR requirements, and subjecting re-fractured or re-completed wells to any of the proposed requirements. We believe the control of those source-types is generally cost-prohibitive.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22. We disagree with the commenter that it would be cost prohibitive to subject refractured or recompleted wells to the fugitive emissions monitoring provisions. As discussed in section VI.F.1.b of the preamble to the proposed rule, the level of fugitive emissions is largely dependent on the number of fugitive emissions components at the site. There is no indication, nor did the commenter provide any, that there are fewer fugitive emissions components at refractured or recompleted wells.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 17

Comment: Off ramp for wells producing less than 15 boepd

Last, as explained in further detail in I. below, Pioneer strongly requests that EPA provide an off ramp and exempt declining producing wells with a throughput of 15 boepd or less from the LDAR program. This is in line with EPA's logic of exempting these low production wells from the LDAR program in the first place; that is, as the production of the well declines, and the throughput and pressures of the stream into associated equipment are subsequently reduced, the equipment's ability to emit VOCs and methane into the atmosphere, and therefore potential for leaks, also declines. This would also be consistent with the revised storage tank provisions in the 2013 Subpart OOOO Reconsideration of Certain Provisions of New Source Performance Standards Final Rule where EPA explicitly allowed tanks to remove control devices if they can demonstrate that their uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 19

Comment: Proposed LDAR exclusions are helpful and an off-ramp for declining sources should be included in the final rule

In the proposed rule, EPA proposes that sites producing less than 15 boepd as wells as sites that are composed of a wellhead only (with no ancillary equipment) be exempt from the LDAR program. Pioneer agrees with and appreciates EPA recognizing these as a reasonable exemption. In support of this proposal, EPA correctly notes:

"We believe the lower production associated with these wells would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emissions requirement on small businesses, in particular where there is little emission reduction to be achieved."

As mentioned above, using the same logic that justifies this exemption – as the production of the well declines, and the throughput and pressures of the stream into associated equipment are subsequently reduced, the equipment's ability to emit VOCs and methane into the atmosphere also declines – Pioneer strongly urges EPA to provide an off ramp and exempt declining producing wells with a throughput of 15 boepd from the LDAR program. This exemption would apply to wells that may have been subject to the LDAR program for a period of time but once their throughput falls below 15 boepd, these wells and associated equipment could withdraw from the LDAR program and no longer be subject to these requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22. We note that per 40 CFR 60.5365a(i)(2) of the final rule, a well site that only contains one or more wellheads is not considered an affected facility for fugitive emissions monitoring.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 38

Comment: EPA proposes to exclude "low production well sites" from the fugitive emission standards. A "low production" well is defined "as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613I(6)(E)."

In support of this proposal, EPA correctly notes:

> We believe the lower production associated with these wells would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement on small businesses, in particular where there is little emission reduction to be achieved.

EPA solicits comment on the appropriateness of this threshold for applying the standards for fugitive emissions at well sites.

TXOGA supports the concept of a low production well exclusion. Imposing controls on low production wells is not cost-effective and the opportunity for reduction is not meaningful. Nor can it "reasonably be expected to serve the interests of pollution control without being exorbitantly costly." As EPA correctly observes, the burden placed on smaller operators, many of whom are TXOGA members, would be great and the potential for emission reduction trivial.

While TXOGA supports the proposed exclusion, we note that it is important for the rule to define barrel of oil equivalent ("BOE") in terms of units of U.S. petroleum barrels of oil per cubic feet of gas to avoid confusion arising out of the different conversion rates available.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 5

Comment: Prescribed Requirements are Disproportional to Potential Emissions Risk: Apache recommends a gas production level of 600 MCF/day (100 BOEgas) as the threshold for entry to and exit from these regulations.

The EPA should consider that every oil and gas well is subject to naturally declining production where the majority of production occurs in the first few years of a well's life cycle. Consequently, the majority of a well's emission potential occurs when pressures and production volumes are high early in the life of the well. The application of stringent rules to aging, low production, low pressure wells is a poor use of capital and results in declining environmental benefit as wells age. In other words the proposed rule imposes uniform costs and management effort across all assets, regardless of their potential emissions.

Apache would favor a program in which costs and effort are to be applied in proportion to potential emissions. This approach could include tiers in which monitoring and control requirements vary based upon the production from the assets in each tier. Assets with higher production rates and correspondingly higher emissions risks would have higher assessment levels than assets with lower production rates and lower emission potential. Importantly, the tiered approach must allow a previously affected facility to be eventually excluded from the rule when the gas production rate associated with that facility declines to such a point where the emission risk is considered de minimis. Apache recommends a gas production level of 600 MCF/day (100 BOE gas) as the threshold for entry to and exit from these regulations.

This concern is echoed for §60.5397a that would require wells with production >15 BOE/day to have an LDAR program. The proposed rules do not provide an endpoint or off-ramp from mandatory monitoring. The prescribed LDAR program becomes less effective over time as leaks are repaired and production declines. LDAR costs, however, are ongoing, creating unnecessary, ineffective spending that would reduce the ability to apply scarce funds to more meaningful emission detection and reduction projects. While the proposed rule extends the time between monitoring to one year (should less than 1% of components be found to have leaks), the LDAR program costs would not diminish and the escalating unit costs of the program would exceed any emission reduction benefits when production values and emission potentials are declining. This is illustrated in Figure 1 where costs rise to almost $1,300 per Mcf of methane reduced corresponding to nearly $2,400 per tonne CO2e abated. See the Section Specific Comments regarding Fugitive Emissions for additional details regarding the costs of the LDAR regulation.

[Figure 1 shows the annual cost per fugitive and CO2e reduced over a 5 year period]

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Anthony J. Ferate
Commenter Affiliation: Oklahoma Independent Petroleum Association (OPIA)
Document Control Number: EPA-HQ-OAR-2010-0505-6810
Comment Excerpt Number: 3

Comment: Our organization has significant concerns about the detrimental impact the proposed rules will have on marginal wells, particularly the additional costs wells that produce less than 90 barrels a month will have to adopt with significant cost and no additional reporting accuracy. The following issues require serious consideration before finalizing this rule:

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 23

Comment: The rule proposes a 15 barrel of oil equivalent per day (BOE/d) threshold for exemption from its wellsite fugitive monitoring based on the average of the first 30 days of production. *See* 80 Fed. Reg. 56,612. We request clarification on whether this exemption will apply to any well that falls below this 15 BOE/d threshold. In addition, we request clarification on the following scenario: if a well is above 15 BOE/d during the first 30 days of production, will it remain in the OOOOa LDAR program indefinitely?

The rule might also consider an alternative exemption: based instead on 300 gas-to-oil ratio (GOR). The proposed rule recognizes oil wells with little to no gas volumes should be exempt from reduced emission completion (REC) requirements based on a low GOR of 300. If gas volumes are this low, gas gathering is uneconomic, and it is no longer cost-effective to require leak detection for little to no methane (or natural gas) reductions. The proposed rule should be revised to exempt low production wells from its LDAR requirements regardless of their initial production rate.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 105.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 8

Comment: Further clarify low production wells to quantify natural gas wells and coal bed methane.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 8

Comment: Antero supports the exclusion of each well at sites with average combined oil and natural gas production being less than 15 barrels of oil equivalent (boe) from the definition of an affected facility under the NSPS. Antero also supports the exclusion of low oil production wells. USEPA's definition of a low oil production well as producing less than 15 boe is an acceptable threshold for that category of well, but USEPA has overlooked well sites that would produce greater than 15 boe and still have very limited VOC and Hazardous Air Pollutant (HAP) emission potential that should also be excluded from the definition of "affected facility."

Antero operates a substantial leasehold position in the dry gas Marcellus play. With respect to Antero's operations, wells drilled in the dry gas Marcellus produce minimal amounts of oil. Therefore these low oil production, high gas production well sites should also be excluded from fugitive emission component monitoring requirements because, of their low VOC and HAP emissions potential and excluded from the definition of affected facility in Proposed 40 CFR § 60.5365a. The use of limited resources to monitor these sites is inefficient and results in resources being improperly directed at sites with limited impacts upon the environment. These "dry gas wells" produce little to no condensate or oil and have been determined by state agencies, such as West Virginia, to be exempt from air permitting requirements due to their limited VOC and HAP emission potential. The West Virginia minor source permitting program does not require an air permit, if the source does not exceed 2 lb/hr or 5 TPY of total HAPs; or 6 lbs/hr and 10 TPY of any regulated pollutant. (W.Va. Code St. R. § 45-13). Because these well sites are *de minimis* emission sources, the imposition of NSPS LDAR requirements would be inappropriate. If such well sites are not excluded, then, they should be subject to less frequent monitoring requirements.

To effectuate these proposed exclusions described above, Antero suggests that the proposed definition of well affected facility at 40 CFR § 60.5365a(a) should be modified to include the following language :

> *(5) A well site that has de minimis emissions (less than 6 lbs/hr and 10 TPY of each criteria pollutant and 2 lbs/hr or 5 TPY of total Hazardous Air Pollutants (HAPs)) is not a well affected facility.*

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22, and DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 3. We also note that this rule covers emissions of GHG in addition to VOC.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.

Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 11

Comment: EPA Must Provide Operators with a Realistic Fugitive Emission Control Applicability Threshold for Well Sites

EPA is proposing to exclude low production well sites, defined by the average combined oil and natural gas production for the wells at the site being less than fifteen barrels of oil equivalent ("boe") per day averaged over the first thirty days of production, from the NSPS OOOOa fugitive emission control requirements. See 40 CFR § 60.5365a(i)(1) proposed in 80 Fed. Reg. at 56664. While QEP thanks EPA for considering the burden and resulting negligible environmental benefit from imposing fugitive emission control requirements on low producing wells, the threshold of fifteen boe per day for new and modified wells is not a realistically useable exemption for industry. A new well producing below fifteen boe per day will often represent an uneconomic well. Under this scenario, operators will be making the decision to shut in the well, long before they will be contemplating whether an exemption from fugitive emission control requirements applies.

QEP assumes that EPA desires to establish a provision in the fugitive emission control program that effectively exempts some new and modified well sites from the program. As such, QEP recommends EPA work with industry to identify a more realistic exemption threshold for new and modified wells.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 25

We did not find any relief from survey requirements for wells that have been temporarily shut in for various reasons. We may shut in a well for economic reasons, where we have low producing oil wells shut in because the cost to operate them is greater than the economic benefit of producing oil from the well. We request that wells that have been temporarily shut in will be exempt from survey requirements until they are returned to operation.

Response: The final rule does not specifically address wells that have been temporarily shut in. Thus, any well site that qualifies as an affected facility under 40 CFR 60.5365a(i) is subject to the fugitive emissions monitoring requirements. Note that per 40 CFR 60.5365a(i)(2) of the final rule, a well site that only contains one or more wellheads is not considered an affected facility.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 6

Comment: The DEP supports EPA's proposals to achieve additional VOC and methane emission reductions from the oil and natural gas sector to the extent that the provisions are at least as stringent or more stringent than the requirements currently being implemented in Pennsylvania under the Air Pollution Control Act, 35 P.S. §§ 4001 - 4015 and implementing provisions in Title 25, Subpart C, Article III (relating to air resources) of the *Pennsylvania Code.* The DEP is concerned, however, that further reductions in methane emissions from natural gas sources located in "dry gas" areas of the Commonwealth (i.e., north central and central regions) may not be achieved under the proposed rules and guidelines. The DEP recommends that EPA explicitly define a "leak" in terms of methane and VOCs to address natural gas operations in "dry gas" areas in the Marcellus Shale Play; the natural gas from the "dry gas" areas in the northeast and north central regions of the Commonwealth is mainly methane.

The DEP has a comprehensive permitting program which authorizes reductions of air contaminants including methane, volatile organic compounds (VOCs) and nitrogen oxides (NOx) from sources at natural gas production, compression, processing, and transmission facilities. The DEP's conditional exemption criteria for sources at well sites and General Permit for sources at natural gas compression and processing facilities require source owners and operators to comply with stringent requirements including a Leak Detection and Repair (LDAR) program for any type of leaking air contaminant. The DEP LDAR criteria and permit conditions specifically target methane emission reductions from the oil and natural gas sector. The NSPS proposal excludes from the fugitive emissions requirements the well sites that contain only wellheads. The preamble states that areas with very "dry gas" tend to be the well sites with only wellheads. Thus, several well sites in dry gas areas would be exempt from LDAR program requirements. However, the DEP requires the LDAR program at all well sites, including well sites EPA has proposed to exempt from regulation. The DEP believes that the final rulemaking should require fugitive methane emission reductions at all well sites.

Response: The EPA disagrees with the commenter. As we stated in the preamble of the proposed rule, well sites that consist only of one or more wellheads have no ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators and pneumatic controllers. Because the magnitude of fugitive emissions depends on how many of each type of component are present, fugitive emissions from these types of well sites are extremely low, and as such regulation of the fugitive emissions are not cost effective. For that reason, we are finalizing the exclusion from the fugitive emissions requirements those well sites that contain only wellheads. We note that state and local air agencies always have the option to be more stringent than the federal program.

Commenter Name: Tom Michels
Commenter Affiliation: ONE Future

Document Control Number: EPA-HQ-OAR-2010-0505-6880
Comment Excerpt Number: 3

Comment: RECOMMENDATION 1: The EPA should exclude low-emitting facilities from the NSPS OOOOa fugitive emissions standards and requirements.

ONE Future's flexible, performance-based system focuses on identifying the most cost-efficient and cost-effective abatement opportunities first, in order to yield the greatest emission reductions, in the shortest amount of time, and at the lowest cost. A natural corollary to this is to eschew wasteful expenditures of capital and manpower whenever possible. It is for that reason that we urge EPA to exclude all low-emitting facilities from the proposed OOOOa standards and requirements related to Fugitive Emissions.

The Proposed OOOOa Rule already excludes the following facilities from regulation on the grounds that the facilities have low emissions and therefore there is minimal benefit from subjecting them to additional NSPS requirements:

1. Low production wells;
2. Wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced; and
3. Well sites that only contains one or more wellheads (i.e., Christmas trees)

The EPA is considering additional exclusions. The preamble to the Proposed Rule seeks "comment on whether there are well sites that have inherently low fugitive emissions, even when a new well is drilled or a well site is fractured or refractured."

The Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has recognized that such *de minimis* exceptions allow agency flexibility in interpreting a statute to prevent "pointless expenditures of effort." These *de minimis* exceptions from the requirements of a regulation may be permissible "as an exercise of agency power, inherent in most statutory schemes, to overlook circumstances that in context may fairly be considered *de minimis*."

In the preamble to final OOOO rule, EPA explains that the *de minimis* doctrine can apply when the source has emission controls in place that are "equivalent to those required for a new source" because, in such a situation, imposing NSPS controls on the source would not yield additional regulatory or environmental benefits.

Therefore, EPA has a firm legal basis for granting *de minimis* exceptions to inherently low-emitting facilities.

In this rule, we urge the EPA to extend the *de minimis* exception to any of the affected sites/facilities with a *potential to emit* less than the values listed below, which are principally derived from the potential uncontrolled rates from the Technical Support Document (TSD):

Table 1: Low Fugitive Methane Emissions Facility Threshold

Segment	Low Fugitive Methane Emissions Facility Threshold (metric tons per year, CH_4)	Comment
Natural Gas Well Site	4	Per well
Oil Well Site	4	Per well
Gathering & Boosting	35	Per station
Transmission	62	Per compressor station
Storage	164	Per storage facility

A site's Potential to Emit can be readily quantified and estimated. In order to establish a given site's potential to emit, a company can use either EPA's GHGRP emission factors or factors generated by direct measurements of the leaks employing generally accepted techniques such as HI Flow samplers at company facilities to develop its potential-to-emit estimates. As long as the potential-to-emit from the fugitive emission source is below the thresholds in Table 1, the facility should qualify for the low emitting facility exception. Should additional wells or compressors be added to the facility, the facility will review its status against the *de minimis* thresholds in Table 1. Any increase above the threshold will make the facility subject to the fugitive emissions standards.

Notably, as part of the proposed Methane Challenge ONE Future commitment option, ONE Future companies will be estimating their emissions, even those not currently reported to the GHGRP due to being below threshold or simply not included. Additionally, ONE Future has also urged EPA to support and facilitate the usage of direct measurements as part of the Methane Challenge, which would facilitate this process.

EPA can have a reasonable assurance that a low-emitting facility cannot exceed its applicable potential emission threshold and therefore continue to qualify for the exception. The general NSPS definitions under 40 C.F.R. §60.14(a)(b) focus on modifications and increases in emission rate "expressed in kg/hr of any pollutant discharged….". The EPA has upheld this concept of design rate and emissions increases in numerous determinations found in the search of the Applicability Determination Index (ADI).

A low-emitting well site's potential to emit fugitive emissions will not exceed that of its initial period of oil and natural gas production. In order to illustrate why this is the case for well sites, Figure 1 depicts the typical production decline curve over the lifetime of a natural gas well. As the figure clearly shows, the *potential* for fugitive emissions is highest during the initial period of production, which is a fundamental characteristic of shale wells. Hence, such facilities, which by their physical or operating conditions have a low potential to release fugitive methane emissions, should be excluded.

[Note: Figure 1 (Illustrative Production Decline Curves for Shale Gas Wells (Source: Penn State University)]

The application of stringent rules to wells with a low potential for fugitive emissions constitutes an inefficient expenditure of capital and resources that could be better utilized elsewhere to achieve greater environmental benefit. Regrettably, however, the Proposed Rule applies uniform costs and management effort across all new, modified, and reconstructed assets on a perpetual basis, regardless of their potential emissions over time.

In the recent past, EPA has acknowledged the fact that emissions decline over time in conjunction with declining well production, and created alternative standards within the relevant NSPS to accommodate changes in how compliance is demonstrated. For example, in its 2013 updates to the Subpart OOOO Rule, EPA established an Alternative Emissions Limit for storage vessels. This provision allows operators to either reduce VOC emissions at a tank by 95 percent, as was required in the 2012 rule; or alternatively, to demonstrate that emissions from a tank have dropped to less than 4 tons per year of VOCs without emission controls. If a storage vessel's uncontrolled VOC emission rates are demonstrated to be less than 4 tpy for at least 12 consecutive months, then the facility can remove the prescribed emission controls. As EPA wrote at the time, "This alternative limit reflects the decline in emissions that occurs at most tanks over time and allows owners/operators to shift control equipment to higher-emitting tanks." Anti-backsliding provisions were included such that if emissions subsequently increase over 4 tpy, the source would need to comply with the NSPS standards.

> **Anti-backsliding provisions are already accounted for in OOOOa.** EPA's proposed OOOOa requirements for Fugitive Emissions, already includes a benchmark for determining whether emissions have increased at an inherently low-emitting source and therefore backsliding has occurred. This benchmark is the "modification" definition. For purposes of the OOOOa Rule, EPA has proposed to define "modification" for well sites as follows, "For the purposes of these fugitive emissions standards, a modification would occur when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured." EPA later justifies this decision by stating:
>
> *"When a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well.* ***Other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site.****"* (Emphasis added.)

Similarly, EPA concludes there will be an increase in fugitive emissions at an existing compressor station only when an operator adds an additional compressor or compression capacity:

> *"..[A] modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. Since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components.* ***Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station.".*** *"* (Emphasis added.)

Therefore, EPA can have a reasonable assurance that unless there is a "modification" at these low emitting sites, there will be no increases in fugitive emissions from the time the facility is placed in service.

Considering the above, we urge the EPA to exclude low-emitting facilities from NSPS OOOOa standards for fugitive methane emissions. In so doing, EPA will permit a more efficient allocation of capital and resources that will facilitate operators to address more cost-effective abatement opportunities elsewhere in their system.

Response: While we agree with the commenter that the EPA has discretion to create *de minimis* exemptions, the final rule does not include exemptions from the fugitive emissions monitoring requirements for facilities with low potential emissions as requested by the commenter. We note that the commenter provided no basis for the suggested *de minimis* thresholds upon which to base such a finding.

In addition, we are unconvinced by the commenter's assertion that the EPA can be reasonably assured that fugitive emissions from a well site or compressor station will not subsequently increase above a calculated potential emissions rate for the facility. Equipment leaks can be expected to occur randomly over time, and in some cases equipment failures can result in extremely high fugitive emissions. It is to be expected that fugitive emission rates will rise over time as more and more components develop leaks with use and wear. In essence, this is the rationale for a periodic fugitive emissions monitoring program – so that such leaks can be detected and repaired soon after they occur.

Regarding other points made by the commenter:

- We agree with the commenter that a shale well's production typically falls over time, but we did not receive data from the commenter showing that low production well sites have lower emissions than non-low production well sites. In fact, the data that were provided during the comment period for the proposed rule indicate that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. Our discussions with stakeholders lead us to believe that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Thus, fugitive emissions would not necessarily decrease as a well's production falls. We believe that the emissions from low production and non-low production well sites are comparable and we did not finalize the proposed exclusion of low production well sites from fugitive emissions monitoring. See section VI.F.1.b of the preamble for more information on emissions from low and non-low production well sites.

- We are not aware of any data indicating that wells with GOR of 300 scf of gas per barrel of oil produced or less would necessarily have less fugitive emissions than higher GOR wells. Therefore, these wells are not exempt from fugitive emissions monitoring.
- Our proposal preamble discussion of modifications at well sites and compressor stations, as cited by the commenter, is not germane. That discussion does not address equipment leaks from existing equipment, which can be expected to increase over time.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)
Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 7

Comment: EPA Should Develop De Minimis Exemption for Small Producers

Production patterns for individual wells are susceptible to unanticipated fluctuations over time. Some companies focus on development of marginal fields and stripper wells, and thus going forward may not be well versed in complying with EPA regulations for larger producing wells. In order to avoid unnecessary administrative expense and hassle, EPA should develop an exclusion for small operators whose average well produces less than 15 boepd. In the private sector, this would provide producers with predictability and aid in simplifying due diligence for asset purchases. On the agency side, this exemption would enable EPA and state regulators to focus their scarce resources where they will be most effective.

But the bottom line, as EPA has acknowledged, is that small operators whose success depends on an accumulation of low profit-margin wells are very vulnerable to unintended financial burdens imposed by the new regulations. Independent producers develop 90 percent of the wells in the United States – producing 54 percent of America's oil and 85 percent of America's natural gas. These companies produce 4 percent of the United States' Gross Domestic Product and reinvest billions of dollars back into the American economy. Many, if not most, of those operators are small, privately owned family businesses in which every dollar is important. Since EPA has acknowledged that marginal wells are not a significant source of emissions, every effort should be made to not impose additional economic burdens on those companies.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 6

Comment: Item -Exemption for "Low Fugitive Emissions Sites"

Under the Proposed OOOOa rules, the US EPA established exemptions for the following facilities mainly based on low emissions from these facilities and therefore minimal benefit from additional NSPS requirements at these sites

1) Low production well sites
2) Wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced
3) Well site that only contains one or more wellheads (christmas trees)

The EPA at page 56639 seeks "comment on whether there are well sites that have inherently low fugitive emissions, even when a new well is drilled or a well site is fractured or refractured"

As explained in *Alabama Power*, the *de minimis* exception allows agency flexibility in interpreting a statute to prevent "pointless expenditures of effort." Further, in the Environmental Defense Fund, Inc. v. EPA, 82 F.3d 451,466 (D.C. Cir. 1996), the courts reasoned imposing NSPS controls on a facility that has low emissions would not yield additional regulatory or environmental benefits. Therefore, EPA is well grounded to afford exemptions to low emitting facilities.

The EPA should consider additional factors and extend any facility with a potential to emit less than the values listed below, which are primarily the potential uncontrolled rates from the Technical Support Document (TSD):

Table 1: Low Fugitive Emissions Facility Threshold

Segment	Low Fugitive Emissions Facility Threshold (metric tons per year, CH_4)	Comment
Natural Gas & Oil Production Site	4	Per Well
Gathering & Boosting	35	Per station
Transmission	62	Per Compressor Station
Storage	164	Per Storage Facility

EPA should consider the fact that the natural gas production at a well declines during the life of a well as illustrated in the figure below. Therefore, fugitive emissions potential is the highest during this period. The application of stringent rules to aging, low production, low pressure wells is a poor use of capital and results in declining environmental benefit as the wells age. In other words the proposed rule applies uniform costs and management effort across all assets, regardless of their potential emissions. EPA has already concluded that under the modification definition that for well sites, fugitive emissions increase from design levels only if a new well is added or an existing well is fractured.

"For the purposes of these fugitive emissions standards, a modification would occur when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured." (FR 56612)

"When a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well. Other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site." (FR 56614)

Similarly, EPA concludes that only when an additional compressor or a physical change to an existing compressor that there will be an increase in fugitive emissions

" .. a modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. Since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components. Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station." (FR 56614)

Therefore, EPA can have a reasonable assurance that unless there is a "modification" at these low fugitive emissions facilities, there will be no increases in fugitive emissions.

SWN also comments that EPA should offer an "off-ramp" for those low fugitive emissions facilities once the potential or actual emissions become less than levels in Table 1. Such facilities will no longer have to comply with the prescriptive fugitive emission monitoring requirements rather could employ a less stringent monitoring to provide reasonable assurance that these facilities are indeed operating below the low fugitive emissions thresholds. Without such a provision these facilities would have to continue expend significant resources and capital to achieve very marginal reductions.

While the "once in, always in" concept is a construct of hazardous air pollutants under Section 112 of the Clean Air Act it has not traditionally been applied in the context of Section 111

NSPS regulations. The policy was enacted in the context of Section 112 to prevent anti-backsliding at sources that successfully installed emissions controls that reduced hazardous air pollutants below certain thresholds.

EPA's proposed fugitive emissions monitoring program does not raise the same anti-backsliding concerns as Section 112 MACT standards, especially at oil and gas well sites mainly due to the fact that after the first few years, the production declines and the fact that new natural gas sites are subject to stringent controls and standards under NSPS OOOO anyway. The potential reductions that can be achieved by continuing to implement LDAR at these sites will be small and instead the capital and resources can be more efficiently deployed for other reductions. These facilities could employ a lower frequency monitoring coupled with desk-top estimation. Should these surveys and desk-top analysis show emissions above the threshold, these facilities would require the sources tore-initiate fugitive emissions monitoring and became affected facilities.

Recommendations:

On the basis of the comments above, SWN recommends that EPA provides an exemption for Low Fugitive Emissions Facilities based on the emissions thresholds referenced in Table 1 (above). We further recommend that the assessment would only apply to fugitive emissions associated with valves, connectors, pressure relieve valves, and open ended lines as these are the only fugitive components for which EPA has existing emissions factors (both in terms of estimating number of components and emissions) under 40 CFR Part 98, Subpart W. Determination would be based on either an actual count of these components (based on process instrumentation design count or physical count) or using the appropriate 40 CFR Part 98, Subpart W (tables W-1B or W-1C) component factors and either the component emissions factors for 40 CFR Part 98 (table W-1A) or actual HiFlow measurement data obtained by the company.

This could be accomplished by adding the following provision to the applicability section 60.5365a(i) Except as provided in §60.5365a(i)(l) through (i)(3), the collection of fugitive emissions components at a well site, as defined in §60.5430a, is an affected facility.

(1) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production, is not an affected facility under this subpart.

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart.

(3) A Low Emissions Facility with potential or actual fugitive component emissions from valves, connectors, pressure relief valves, and open ended lines below the levels in the Table 1 below. Demonstration of the exemption may be based on using EPA component count (per 40 CFR Part 98 Table W -1 B or W -1 C), process diagram or physical component count, EPA emissions factors (per 40 CFR Part 98 Table W - 1A) or actual quantification measurements (e.g. HiFlow)

Table 1: Low Fugitive Emissions Facility Threshold

Segment	Low Fugitive Emissions Facility Threshold (metric tons per year, CH_4)	Comment
Natural Gas & Oil Production Site	4	Per Well
Gathering & Boosting	1	Per well
Oil Well Site	35	Per station
Transmission	62	Per Compressor Station
Storage	164	Per Storage Facility

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 3.

In addition, in the absence of the *de minimis* exemptions suggested by commenter, there is no basis for the commenter's suggestion that the final rule should provide an "off ramp" for affected well sites and compressor stations when their emissions fall below the commenter's suggested exemption thresholds.

We disagree with the commenter that the "once in, always in" policy is limited to rules developed pursuant to section 112 of the CAA. The EPA historically has never let facilities in and out of affected facility status and is consistent in subpart OOOOa.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 105

Comment: The 15 BOE Exemption In §60.5365a(i)(1) Recognizes Low Volume Production Being Lower Emission And Sensitive To Additional Cost Burden, But Is Not The Only Exemption To Consider

The 15 barrel of oil equivalent per day (BOE/day) exemption will generally not be useful for new sites since this level of production is consistent with a stripper well. Stripper wells represent wells near the end of their productive life not the beginning. Consequently, it would be rare for operators planning to construct well sites with initial production at this low level. The usefulness of this provision is at the end of a well's productive life as an off ramp to exempt being an affected facility much like being able to remove a control device at less than 4 tpy of storage vessel emissions or for sites that are modified and pulled into the rule. It would however be useful for modified or reconstructed sources.

Another exemption is based on GOR. EPA recognizes in this proposal that oil wells with little to no gas volumes should be exempt from REC requirements based on a low GOR of 300; this same GOR should be another threshold to exempt well sites from leak detection as well. If gas volumes are so low that gas gathering is uneconomic, it is not cost effective to have leak detection requirements for little to no methane or natural gas reductions. Since VOC reduction alone is not cost effective, the lack of natural gas production should be a factor in affected facility exemptions

Rule text change recommendation to reflect these comments are provided in Section 27.2.12.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22, regarding the EPA's decision not to include the proposed exemption low production well sites in the final rule.

Regarding the suggested exemption for well sites with GOR less than 300 scf of gas per barrel of oil produced, the EPA is not aware of any data indicating that these wells would necessarily have less fugitive emissions than higher GOR wells. Therefore, we are not implementing the commenter's suggestion in the final rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 106

Comment: Fugitive Emissions Do Not Correlate To Production

The proposed rule provides a threshold for an affected facility under §60.5365a(i)(1) "A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production, is not an affected facility under this subpart." In the preamble, EPA solicited comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions, specifically on the relationship between production and fugitive emissions over time. EPA also solicited comment on the appropriateness of this threshold for applying the standards for fugitive emission at well sites, in addition to whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

Fugitive emissions do not correlate to production. A production rate gives no indication of the type or number of equipment that are located at the site. In addition, this exemption is irrelevant for new well sites which would not be economical to produce at 15 BOE/day. As stated in our comment above (see 27.2.3), this exemption should also be considered as an off-ramp to §60.5397a applicability or exemption in the rare event of a modification to a stripper well. However, API believes it more appropriate and would prefer that the rule be based on the process equipment located at the site rather than a low production rate since fugitive emissions are based simply on the number of components associated with the process equipment. As indicated in sections 27.2.6 and 0, API believes that sites with equipment configurations or component counts less than the model plants should be exempt from the LDAR requirements, as based on EPA's analysis, LDAR is not cost effective at sites with fewer equipment/components.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22, regarding the EPA's decision not to include the proposed exemption for low production well sites in the final rule.

See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 109, regarding the commenter's suggestion to exempt will sites with equipment configurations or component counts less than the model plants.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 112

Comment: Produced Water Injection Facilities Should be Exempt from the LDAR Requirements

Injection well facilities receive produced water that has been physically treated to remove liquid hydrocarbons and natural gas before arriving at the facility. For the following reason these facilities should not be included in the fugitive monitoring program:

They contain operations and activities associated with produced water delivery, storage, and injection.

These facilities are constructed to manage a producing field's water production.

Natural gas is not typically associated with these facilities.

There are limited liquid hydrocarbons present at these facilities. Thus, there are very limited emissions from the storage vessels therefore storage vessels vent to atmosphere and are not controlled. Hydrocarbons are removed from the water prior to arriving at the injection well facility to avoid loss of revenue.

There is little to no environmental benefit in subjecting these injection well facilities to LDAR requirements and requiring additional resources which could be used for a better purpose. If EPA had considered the cost effectiveness of LDAR on injection well facilities, the results would show a net negative benefit. Therefore, injection well facilities should be excluded from the LDAR requirements. The recommended regulatory change for this exemption is provided in Section 27.2.12.

Response: The EPA disagrees with the commenter that injection wells should be exempt from the fugitive emissions monitoring requirements. In the specific example given by the commenter, it appears that the hydrocarbon content of the liquid being injected is low. However, there is no indication that the liquid processed at all injection wells would be treated to the extent described for this one situation. For example, another operator may conclude that it is not economically justified to treat the liquid and proceed to inject the liquid without further treatment. Had we included the exemption requested by the commenter, fugitive emissions from this injection well, which would likely be significantly higher than the commenter's example, would go unabated.

We also considered the commenter's suggested exemption in practical terms. Because the hydrocarbon content of the injected liquid can vary, we would have to determine at what hydrocarbon concentration the cost of control would no longer be acceptable. .

Additionally, we note the final rule does not include exemptions from the fugitive emissions monitoring requirements for facilities with low potential emissions, as we have no basis for a *de minimis* threshold upon which to base such a finding.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 30

Comment: As noted above, nearly all PIOGA operators are small business entities and are involved in the development of "conventional" or vertical wells that typically meet the "low production site" criteria as proposed in Subpart OOOOa. PIOGA agrees with U.S. EPA that "…the lower production associated with these wells would generally result in lower fugitive emissions" and that "…fugitive emissions at low production well sites are inherently low…" PIOGA believes that the low production well site threshold of 15 boe based on the definition of a stripper well property in IRC 613A(c)(6)(E) is reasonable. However, the metric for establishing the 15 boe/day values in the referenced definition is on a calendar year basis, not on the first 30 days of operation. Basing the exemption threshold criteria on average combined oil and gas production over only the first 30 days of production may not be representative for many low production (i.e., stripper) wells in Pennsylvania. For example, at a typical oil well in Southwestern Pennsylvania, initial production could peak between 20 and 50 bbl/day within the first few weeks or first month of production following completion, but then drop very quickly to less than the proposed 15 bbl/day threshold. PIOGA suggests that the 15 boe threshold be based on the average production over the first 90 days of production for suspected stripper wells. Given the ability of operators within a given region to accurately predict well performance, a 90 day evaluation period would provide a more representative characterization of the long-term productivity of a given well. PIOGA also believes that "low pressure wells" should be excluded from the fugitive emission requirements of proposed Subpart OOOOa.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 22.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 23

Comment: Removal from Monitoring

We did not find a way to remove a well head or tank battery from the monitoring program once the facility meets EPA's threshold to provide monitoring. NSPS OOOO provided methods to remove tank facilities from the program. What are the requirements that a wellhead and/or tank facility may be removed from the monitoring program, other than being completely removed from service?

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 6.

Commenter Name: Tom Michels
Commenter Affiliation: ONE Future
Document Control Number: EPA-HQ-OAR-2010-0505-6880
Comment Excerpt Number: 4

Comment: EPA SHOULD CREATE AN "OFF-RAMP" FOR LOW-EMITTING FACILITIES.

ONE Future urges EPA to provide an "off-ramp" out of the proposed OOOOa Fugitive Emissions requirements for those well sites and compressor stations that may transition into "Low-Emitting Facility" status, once their potential emit diminishes to a level equal to or less than the applicable thresholds we have identified in Table 1.

Establishing an off-ramp would acknowledge the natural decline curves associated with certain sites, and the attendant reductions in a sites potential to emit. Such facilities would be freed of some of the stringent and prescriptive fugitive emission requirements proposed in OOOOa, and could instead be managed under a more data-driven and risk-based inspection schedule that is more appropriate to the facility's profile. Without such a provision, companies would realize progressively diminishing returns (as measured in abated emissions) on the significant capital expenditures required by the Proposed Rule.

While the "once in, always in" concept is a construct of hazardous air pollutants under Section 112 of the Clean Air Act, it has not traditionally been applied in the context of Section 111 NSPS regulations. The policy was enacted in the context of Section 112 to prevent anti-backsliding at sources that successfully installed emissions controls that reduced hazardous air pollutants below certain thresholds.

EPA's proposed fugitive emissions monitoring program does not raise the same anti-backsliding concerns as Section 112 MACT standards, especially at oil and gas well sites, mainly due to the fact that after the first few years, the production declines and the fact that new natural gas sites are subject to stringent controls and standards under NSPS OOOO anyway. The potential reductions that can be achieved by continuing to implement LDAR at these sites will be small and instead the capital and resources can be more efficiently deployed for reductions under the EPA Methane Challenge (ONE Future) program. These facilities could employ a lower frequency monitoring coupled with desk-top estimation. Should these surveys and desk-top analysis show emissions above the threshold, these facilities would require the sources to re-initiate fugitive emissions monitoring and became affected facilities.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 6.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 24

Comment: EPA Should Not Apply a "Once In, Always In" Policy to Fugitive Emissions Monitoring. GPA requests that EPA clarify in the final rule that the agency will not apply the "once in, always in" policy to affected facilities subject to fugitive emissions monitoring under Subpart OOOOa. EPA appropriately recognizes that fugitive emissions monitoring will not be cost-effective in all circumstances and, as a result, is proposing thresholds that must be exceeded before fugitive emissions monitoring is required. GPA urges EPA to clarify in the final rule that if an affected facility falls below EPA's affected source thresholds, it will no longer be considered an affected facility and, thus, will no longer have to comply with the fugitive emissions monitoring requirements. Without such a provision, GPA's members would face uncertainty regarding the regulatory status of affected facilities that fall below these thresholds and could be required to continue to conduct costly fugitive emissions surveys that will produce small emission reductions.

For example, EPA is proposing that a storage vessel will be an affected facility if its "potential for VOC emissions [is] equal to or greater than 6 tpy." Proposed 40 C.F.R. § 60.5365a(e). Due to changes in operations or changes in the types of hydrocarbons stored in a storage tank, the tank's potential to emit may change over time. Thus, after initially exceeding the 6 tpy threshold and becoming an affected facility under Subpart OOOOa, a storage tank could subsequently reduce its potential to emit below the 6 tpy threshold. Under such circumstances, GPA believes it is inappropriate to continue to regulate the storage vessel as an affected facility with compliance obligations under Subpart OOOOa. Thus, for storage vessels and other facility types with applicability thresholds, GPA urges EPA to clarify that, if the source's emissions or potential emission fall below relevant applicability thresholds, the facility will no longer be considered an affected facility under Subpart OOOOa and will not be required to comply with Subpart OOOOa requirements.

As an initial matter, the "once in, always in" policy was developed in the context of EPA's regulation of hazardous air pollutants under Section 112 of the CAA and has not traditionally been applied in the context of Section 111 NSPS regulations. See EPA Memorandum, Potential to Emit for MACT Standards – Guidance on Timing Issues 9 (May 16, 1995).7 The policy was enacted in the context of Section 112 to prevent anti-backsliding at sources that successfully installed emissions controls that reduced hazardous air pollutants below certain thresholds. EPA's concern in adopting the policy was that sources could "backslide from MACT control levels by obtaining potential-to-emit limits, escaping applicability of the MACT standard, and [subsequently] increasing emissions to the major source threshold." Id.; see also Wildearth Guardians v. Lamar Utilities Bd., 932 F. Supp. 2d 1237, 1245 (D. Colo. 2013).

EPA's proposed fugitive emissions monitoring program does not raise the same anti-backsliding concerns as Section 112 MACT standards. Instead, given the costs and burdens associated with conducting fugitive emissions surveys, the affected facility thresholds for well sites and compressor station sites reflect a balance between those costs and the incremental reduction in methane emissions associated with monitoring certain facilities. Simply put, for smaller facilities, the potential for fugitive emissions is also smaller and imposing onerous fugitive emissions monitoring requirements will not be cost effective.

Therefore, GPA urges EPA to clarify that well sites and compressor station sites that fall below the affected facility thresholds will no longer be considered affected facilities. Due to frequently changing conditions in oil and gas production, production volumes at individual wells can change over time. Thus, over time, an individual well's production may fall below the 15 barrels of oil equivalent per day threshold that EPA has established for fugitive emissions monitoring. EPA should clarify that, given the reduced risk of leaks associated with low-volume wells, 80 Fed. Reg. at 56,612, the well site is no longer an affected facility. Likewise, as changes take place on broader scales, gathering and boosting needs may also change. Thus, if an existing compressor station initially triggers NSPS by adding new compressors or otherwise increasing capacity in a manner that could increase fugitive emissions, it should no longer be considered an affected facility if the new compressor(s) are removed or the capacity is otherwise reduced back to prior levels. There is no concern with respect to anti-backsliding because the proposed regulations would require the sources to re-initiate fugitive emissions monitoring if they once again exceed the relevant thresholds and again become affected facilities. Alternatively, at a minimum, even if EPA determines that such sources will remain affected sources, it should clarify that those sources are not required to conduct fugitive emissions monitoring surveys if they fall below the affected facility thresholds.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 6. The comment on an off-ramp for storage vessels is out of scope for this action.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 39

Comment: Finally, while we support the exclusion [of low production wells from fugitive monitoring requirements], it is most useful as an off-ramp for leak detections since any low volume production is also indicative that a well is approaching the end of its life. In such cases, any fugitive monitoring is not going to be achieving emission reductions that EPA would estimate for a well at normal production levels. Therefore, monitoring would not be cost-effective under CAA Section 111 and the BSER standards EPA and the courts have established. Similar to allowance for storage vessel control removal, TXOGA recommends cessation of leak detection applicability if less than 15 BOE/day production is sustained continuously for any 12 month period.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 6.

Commenter Name: D. Curran
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5337
Comment Excerpt Number: 3

Comment: Second, even if the oil and gas industry is taking steps to reduce their methane emissions, and the evidence suggests they are, that does not imply that methane emissions regulations are inappropriate or unnecessary. The motivation to regulate emissions comes from the President's and EPA's efforts to combat the harmful effects of climate change. The extent to which methane emissions are regulated should be determined in an appropriate manner which accounts for costs, as EPA is required to do. However, the regulations should also be a reflection of the President's and EPA's policy objectives. Any reductions in methane emissions from voluntary industry actions are a result of cost considerations only – they are not a reflection of any policy objectives. There is no reason to believe that cost considerations alone will lead the oil and gas sector to enact methane emissions reductions on the scale required to achieve the climate change policy objectives of the President and EPA.

The fact that the oil and gas sector is already taking steps to reduce methane emissions should in no way be seen as an impediment to regulating methane emissions. Instead, it should be seen as proof that methane emissions can be achieved in a cost effective manner, and that the US does not need to make a tradeoff between environmental stewardship and economic growth.

Response: The EPA appreciates the commenter's input. The final rule is a reflection of the President's and the EPA's policy objectives. Subpart OOOOa is a key component, under the President's Climate Action Plan, to achieving the goal of cutting methane emissions from the oil and gas sector by 40 to 45 percent of the 2012 levels by 2025. However, the rule is not the only component in this plan and emission reductions will be achieved through other mechanisms as well.

We greatly appreciate the voluntary measures undertaken by many stakeholders in the oil and natural gas production industry. We believe that we have shaped the final rule such that these stakeholders will be able to more readily implement the standards given their existing programs.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 15

Comment: While the use of incentives are fine, as EPA's Gas Star program illustrates, still not every participating operator will chose to comply with a voluntary incentive program at every location, every time. Additionally, such programs generally attract the 'Best of the Best' operators that are already taking such measures. Incentive programs will not attract operators who generally employ lesser than best practices. Thus, in order to achieve corporate-wide emission reductions, regulations are the key tool to make that a reality. Those living and attending school near well sites and facilities should all have the benefit of improved standards. The reliance on a voluntary program provides a willy-nilly approach to the public's health and safety for those living and attending school near well sites and facilities. Everyone is worthy of the benefit of the better standards, not just those who happen to live or attend school near a voluntary participants well sites and facilities. Thus, we recommend regulations over voluntary programs every time.

Response: We agree with the commenter that not all owners and operators will implement voluntary programs. In order to achieve progress in reducing emissions, it is important to establish Federal standards. Federal standards will yield a consistent and accountable national program and provides a clear path for states and other federal agencies to align their programs.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 39

Comment: We applaud those operators who may already have in place, and are implementing, corporate-wide fugitive emissions monitoring and repair programs at their well sites that are equivalent to, or more stringent than the EPA's proposed standards. However, as mentioned in the published notice, this is SOME operators, not all. It has been suggested that a good regulatory approach makes best practices the standard practice. Lacking that regulatory approach, there are going to be some operators, not all, that may not have corporate-wide fugitive emissions monitoring and repair programs for well sites. We also see, that generally, the operators who do employ more responsible and "better" best practices are those operators that are more attuned to their footprint and effect on the communities in which they work. We know first-hand that is not all operators. Further, operators who do employ these more stringent than the EPA's standards have the resources and shareholder support to do so. Streamlining voluntary efforts is not protective of public health and safety when insufficient attention has been made to adequately and effectively determine safe distances for health based setbacks of well sites. Therefore, we recommend regulations rather than voluntary efforts.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 15. The EPA greatly appreciates the voluntary measures undertaken by many stakeholders in the oil and natural gas production industry. We believe that we have shaped the final rule such that these stakeholders will be able to more readily implement the standards given their existing programs.

Commenter Name: Camilla Feibelman
Commenter Affiliation: Rio Grande Chapter of the Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-6895
Comment Excerpt Number: 4

Comment: Of the over 475 natural gas producers in New Mexico, fewer than 10 have joined EPA's Natural Gas STAR Program, a voluntary program that encourages companies to stop existing methane leaks and prevent future ones. This demonstrates why voluntary measures are inadequate to address this problem. Therefore, New Mexicans are counting on the EPA to adopt rules that will help mitigate the impacts of climate change by curbing dangerous methane pollution, while at the same time improving the health of workers and residents by reducing VOCs and hazardous air pollutants (HAPS) that are emitted alongside methane.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 15.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 96

Comment: EPA may expect the oil and gas industry to point to reduction in methane emissions from frac and natural gas wells since 2005 and that voluntary compliance is the best approach. In our experience, voluntary compliance is possible with some elements of the industry, but not all.

Without mandatory standards, it's unlikely that all elements of the industry will implement necessary controls.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 15.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 123

Comment: It is well-known that this industry, for the most part, refuses to use best practice unless required to do so. Voluntary programs certainly don't work. We need rules like this one to actually fix the problem.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 15.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 76

Comment: If we are going to cut methane emissions 40 to 45 percent by 2025, these rules and regulations need to be mandatory. The current voluntary program, Natural Gas STAR Program, is only utilized by two percent of Pennsylvania operators on existing sources. This is simply not enough.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 15.

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 46

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 20

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number; 20

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 28

Comment: Finally, the Methane NSPS is unnecessary because the oil and gas industry is already effectively addressing methane and VOC emissions through voluntary programs. For example, many industry members have entered into the voluntary Natural Gas STAR Methane Challenge

Program, which includes recommendations to repair detected leaks. In fact, EPA's own estimates indicate that methane emissions from the oil and gas sector have been steadily decreasing for more than a decade. The oil and gas sector has reduced emissions by more than 20 million metric tons of CO_2 equivalent since 1990, despite the tremendous increases in production that occurred during this same period. The industry is continuing to find innovative and cost-effective ways to reduce emissions, but EPA's proposed regulations would stymie that innovation by forcing every business to comply with a one-size-fits-all approach. Instead of mandating a particular set of requirements, EPA should continue to monitor progress in the oil and gas sector to evaluate whether additional regulations are really necessary, and, if so, what form they should take.

Response: The EPA greatly appreciates the voluntary measures undertaken by many stakeholders in the oil and natural gas production industry. As is evidenced by the statistics quoted by the commenter, the industry has made commendable strides in voluntarily reducing emissions. However, there is still a large portion of the industry that has not implemented voluntary measures or has implemented them on a limited basis. Considering the health and environmental impacts attributable to GHGs and VOCs emitted by this source category and the proximity of many oil and natural gas facilities to densely populated urban areas, we believe a national rule is necessary for the protection of human health and the environment. See response to DCN EPA- HQ-OAR-2010-0505-6857, Excerpt 35, for further discussion.

Based on the information available to the EPA, a large portion of emission reductions from voluntary measures undertaken by the industry appear to be related to fugitive emissions monitoring programs. The final rule includes provisions for fugitive emissions monitoring programs as well. We have added a procedure at §60.5398a of the final rule for owners or operators of affected facilities to apply to the Administrator for a determination under section 111(h)(1) of the CAA of whether "an alternative means of emission limitation" will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §60.5397a." Such an alternate means may include corporate fugitive emissions monitoring programs that deviate from the requirements of §60.5397a. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 15

Comment: Industry has also partnered with EPA in voluntary programs in order to address concerns about gas leaks. In addition, many companies already have company-wide compliance plans in place designed to detect and repair large leaks. EPA should continue to encourage these industry-generated improvements, rather than mandate a one-size-fits-all approach through the proposed NSPS.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46.

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 20

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 20

Comment Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882; Excerpt Number: 13b

Comment Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 96, 97, 98

Comment: *Recommendations:*

1. EPA should withdraw the Methane NSPS and allow the industry to continue to address natural gas emissions through best practices.
2. Alternatively, EPA should exempt affected facilities in states with their own state VOC and methane emissions regulations from the requirements in the Methane NSPS.
3. EPA should create a mechanism by which it can review the regimes in individual states and grant exemptions to facilities within those states that are in compliance with state regulations.
4. EPA should consult with its state counterparts to determine ways to ensure that the Methane NSPS is not unnecessarily duplicative of state requirements, and does not create conflicts with existing state requirements.

Response: The EPA disagrees with the commenters' recommendation that LDAR monitoring be withdrawn from the final rule. We acknowledge that several states have implemented leak detection and repair programs for compressor stations which we reviewed and evaluated during our analyses for the final rule. See discussion in the State LDAR comparison Memo in the Oil and Natural Gas docket. Additionally, see responses to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46, and DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 3

Comment: Southwestern Energy's comments primarily relate to the proposed revisions applicable to fugitive component and equipment leaks. SWN has been and remains a proponent of voluntary Leak Detection and Repair (LDAR) programs to address fugitive emissions control.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 30

Comment: In lieu of the proposed NSPS and incorporated LDAR requirements USEPA should rely on the Natural Gas STAR Methane Challenge Program Proposal

Consistent with the discussion above that USEPA does not have the legal authority to implement methane reductions through the NSPS proposal, Antero suggests that the proposed voluntary Natural Gas STAR Methane Challenge Program ("Methane Challenge ") (PDF) would provide a new mechanism through which oil and gas companies could make and track ambitious commitments to reduce methane emissions. This program is a more appropriate tool to address, manage, and reduce methane emissions. As USEPA has indicated, "this new program has the capability to comprehensively and transparently reduce emissions and realize significant voluntary reductions in a quick, flexible, cost-effective way."

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 11

Comment: In addition, for companies such as Dominion, extensive voluntary measures to reduce methane have been in place for a number of years, including a directed inspection and maintenance (DI&M) program designed by Dominion, which has achieved significant reductions in fugitive methane emissions at compressor stations.

Many Dominion facilities have implemented DI&M as a part of participation in EPA's Natural Gas STAR program or to comply with other regulatory requirements. With the promulgation of the proposed regulation, these facilities would potentially be subject to dual and unnecessary duplicate requirements which do not contribute to any significant environmental benefit. We recommend that for facilities which have a well-documented leak monitoring and repair or DI&M program, EPA exempt these facilities from the leak monitoring/repair programs identified in the proposed regulation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 11

Comment: The proposed LDAR program is highly problematic in numerous respects and would be extremely difficult and costly to implement, all while providing little emissions benefit over and above state and voluntary operator programs. There are proven feasible and cost-effective alternatives to EPA's proposed LDAR program. These alternatives are flexible, cost-effective, and provide the same (or improved) benefits to the environment. Such alternatives include corporate-wide programs executed voluntarily, and compliance with various state-mandated regulatory programs. Other programs-such as those modeled after directed inspection & maintenance ("D&IM") programs-allow operators to focus on high and frequent emitters.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46 and DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 110

Comment: Operators are already implementing voluntary leak detection–repair -- detection measurements based on regulatory and voluntary programs. EPA's in a position to allow such existing leak detection and repair programs to satisfy federal requirements. This will incentivize companies to continue to develop innovative and cost-efficient strategies around leak detection and repair.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015;9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 106

Comment: My first point, our industry has voluntarily led the way in its pursuit of improved operations to safely maximize the recovery and capture of these valuable oil and gas resources. We're incentivized to do that. And many of these leaking technologies that have been broadly used by industry were subsequently incorporated by EPA into its Natural Gas STAR Program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 25

Comment: In addition to these regulatory and cost considerations, it is important to note that Kinder Morgan primarily operates high-pressure pipelines. For the high pressure pipelines, Kinder Morgan does not have the “leak tolerances” that perhaps others operating lower pressure gathering and utility service lines are allowed. A leak from a high pressure natural gas pipeline in the transmission or storage sector can result in a serious event that good operation and maintenance seeks to avoid. To avoid such events, Kinder Morgan devotes considerable money, technology, labor, and other resources to identify pipeline sections that need to be repaired or replaced, even in the absence of methane regulations requiring reduction of leaks. Such voluntary and company-specific methods should not only be allowed but should be promoted in lieu of a command and control regulation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 28

Comment: Kinder Morgan supports a company-driven fugitive monitoring program as long as the required program allows for use of a DI&M program and not an across-the-board LDAR program. EPA recognizes that the majority of fugitive methane and VOC emissions come from a minority of components (the so-called “gross emitters”). Through significant experience implementing voluntary and other programs (such as those under Subpart W, NSPS KKK, and NSPS OOOO), Kinder Morgan believes that a DI&M program more effectively and efficiently addresses fugitive emissions. See Section V(C), below, for further discussion regarding reliance on company-driven DI&M in lieu of NSPS OOOOa’s proposed LDAR.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 46.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 7

Comment: EPA should accept INGAA's Directed Inspection and Maintenance Program since it provides a robust alternative to the proposed leak monitoring and repair program.

The vast majority of leaks from the T&S sector can be addressed by INGAA's DI&M program. As recognized by EPA's Natural Gas STAR Lessons Learned document, DI&M is an effective programmatic approach that focuses on large leaks. Further, EPA's GHG reporting program will provide the verification that methane leaks are being identified and repaired under DI&M.

The INGAA DI&M program provides the structure, program elements and procedures for development of a company-specific DI&M program that focuses on key leak sources within a facility that pose a higher probability of being "gross emitters" or "super emitters." These sources require measurement under EPA's Subpart W reporting program. They include reciprocating compressor rod packing, centrifugal compressor wet seal degassing vents, compressor blowdown valves, compressor isolation valves and scrubber dump valves. The INGAA DI&M program also includes centrifugal compressor dry seals for completeness.

INGAA's DI&M program also includes adaptive management to refine facilities based on data collected, tracking of leaks, and repair of leaks, among others. Each of these components addresses programmatic requirements for a leak mitigation program analogous to program criteria included by EPA in the Proposed Rule. Specifically, INGAA's DI&M program provides for an annual survey (consistent with Subpart W) into the DI&M program. The program would involve condition-based maintenance for rod packings and wet seals and annual leak surveys for the key compressor station components that have the greatest potential for emissions.

INGAA's DI&M program is supported by emissions data from the transmission segment reports submitted to EPA under Subpart W of the GHG Reporting Program (GHGRP). Figure 1 illustrates data from EPA's website for the first three years of Subpart W reporting. The vast majority of compressor station emissions are from reciprocating compressors, centrifugal compressors and tanks (i.e. scrubber dump valves) rather than component leaks. Two Subpart W emission sources—pneumatic devices and blowdowns—are not fugitive emissions. Compressor and storage tank emissions are associated with a select and limited number of components, while the proposed separately tabulated "leaks" category is the cumulative emissions from screening thousands of additional components throughout a facility. This "leaks" source category comprises a relatively small percentage of total leak emissions.

[The commenter provided a bar graph of the CO2e emissions per facility using Greenhouse Gas Reporting Data from reciprocating and centrifugal engines, leaks, pneumatics, blowdowns and tanks]

The INGAA DI&M program does not include this other equipment "leaks" category, since it requires surveying hundreds of additional components that account for only a relatively small portion of the total emissions from the four types of leak sources included in Subpart W.

INGAA's DI&M program is a preferred method since it is effective at reducing methane emissions by identifying and repairing leaks at compressor stations. It is a less burdensome, less disruptive and less costly way of meeting EPA's objective of reducing methane emissions by identifying and repairing leaks at compressor stations, while considering the magnitude of leaks and practical matters that affect repair schedules. It can achieve similar reductions at lower costs by avoiding surveying thousands of pieces of components that it has been documented account for only a relatively small amount of the total emissions, and by avoiding repairs that are not cost effective to address (i.e., small leaks with high repair costs or practical operational matters affecting the repair schedule). INGAA's DI&M program would implement an annual inspection, maintenance and repair program, in which repairs were made consistent with safety and common sense timing. The affected facilities would identify and repair leaks based upon the severity of the leak in a manner that minimizes compressor station downtime.

INGAA recommends that EPA adopt INGAA's DI&M program, which focuses on identifying and repairing the largest leaks, rather than focusing on all leaks, including insignificant leaks.

[In the appendices to their comments, the commenter provided a DI&M White Paper (Appendix A) and DI&M Guidelines (Appendix C)]

Response: In developing the fugitives program in the final rule, the EPA aimed to achieve certain principles as described in section VI.F of the preamble to the final rule. With these principles in mind and based on our consideration of the comments received including information received on voluntary efforts and Directed Inspection and Maintenance Programs, we have made changes to the proposed standards for fugitive emissions from well sites and compressor stations. The final rule refines the monitoring program requirements while still achieving the main goals. We appreciate the commenter's information on Directed Inspection and Maintenance (DI&M) Programs and agree, DI&M programs can be a flexible tool to identify and repair certain emissions sources at oil and natural gas facilities. However, the EPA disagrees that DI&M programs represent the Best System of Emission Reduction (BSER) for the purposes of developing a consistent national New Source Performance Standard. In order to achieve the goals indicated above, the EPA is finalizing quarterly monitoring and repair at compressor stations. Monitoring of the components must be conducted using optical gas imaging (OGI) and repairs must be made if any visible emissions are observed in accordance with the general duty provisions specified within the final rule. Method 21 may be used as an alternative to OGI at a repair threshold level at 500 parts per million (ppm). Please see section VI.F of the preamble to the final rule for more information.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 6

Comment: The INGAA DI&M facilitated through the Methane Challenge Program has the ability to achieve methane reductions more quickly from existing facilities than the Proposed NSPS OOOOa Rule which only affects new or modified facilities. Failure by EPA to recognize equivalency of DI&M under the Methane Challenge Program with NSPS OOOOa's fugitive monitoring requirements would greatly dis-incentivize companies from participating in the Methane Challenge. The logistics of conducting both a voluntary DI&M program at existing sources and an NSPS OOOOa fugitive emissions monitoring program at new and modified sources (or both at the same source if that source is modified) is daunting and logistically difficult. Accordingly, Kinder Morgan believes that many companies will make the decision not to participate in the Methane Challenge Program if they also have to comply with NSPS OOOOa fugitive monitoring. In effect, this will likely result in less emissions reductions overall because the number of existing sources that could achieve reductions under the Methane Challenge Program is far greater than the sources that would be covered by NSPS OOOOa. Ultimately, implementation of the INGAA DI&M Guidelines in lieu of an NSPS OOOOa LDAR program would provide appropriate regulatory streamlining, comprehensive progress tracking, and continued achievement of equal or better emissions reductions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 33

Comment: We also wish to remind you that many of these programs are voluntary, and that particularly in the oil and gas industry sector, which produces an estimated 30 percent of fugitive methane and VOCs into the atmosphere, voluntary programs are, as Will Shakespeare once said, "honored more in the breach than in the commission."

Although emission-cutting technologies have been around for years, as have common sense solutions, like regularly checking for leaks, many companies simply don't bother to take advantage of these cost-effective opportunities and continue to dump an estimate nine million tons of methane and other toxic chemicals like benzene into our atmosphere every year, enough to heat more than five million homes.

Not only is this a careless and easily preventable waste of a valuable commodity, but it contributes significantly to health problems like respiratory diseases and cancer, not only among oil and gas industrial employees, but also in neighboring communities, where some of our most vulnerable citizens like children, the elderly, and those who can least afford it are subjected to millions of dollars of unnecessary healthcare costs each year.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6787, Excerpt 15, and DCN-HQ-OAR-2010-0505-6857, Excerpt 35.

4.8 Compliance

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 18

Comment: If wind speed is an affecting component of surveys as stated on pages 56635, column 1, and 56638, column 3, under section VIII G. 1. Fugitive Emissions from Well Sites, are there times that this would require a survey to not be conducted? This will be an issue in many areas where potentially crews could drive hours to a location and then be unable to perform the survey due to weather conditions. Additionally, due to the remoteness of many facilities, weather conditions could be acceptable at the time of departure and 3 hours later upon arrival unacceptable. Yet this would cost the company for the consultant and the repair crew, as well as releasing fugitive dust and vehicle emissions to accomplish nothing. How does the agency propose to handle issues like this to minimize emissions?

Response: The EPA recognizes that weather conditions play a role in whether OGI surveys can be performed. However, it is beyond the scope of the final rule to account for every weather condition that may be experienced. It is the responsibility of the owner or operator in conjunction with the OGI contractor (if applicable) to assess OGI instrument capabilities, the current and predicted weather conditions and make the decision as to whether proceeding with the survey is advisable. We also note that the final rule allows the use of Method 21 as an alternative to OGI, which may lead to fewer weather-related issues when conducting surveys.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 21

Comment: Specific to the Proposed Rule LDAR requirements, given the timing of the Proposed Rule, EPA may be requiring LDAR programs to be initiated (and then repeated) during winter months, where harsh and cold conditions predominate in Wyoming. In addition to weather concerns, many areas in Wyoming contain disturbance stipulations for wildlife, which also poses problems when trying to access these areas during these stipulated timeframes. These will pose serious difficulties for implementation. In many western mountainous areas like Wyoming, winter weather makes it difficult to visit well sites that can be remote and widely scattered. It also may not be possible to utilize optical gas imaging ("OGI") methods in winter conditions, since visual detection of leaks requires a temperature difference between the leak and ambient air. Delta temperatures between gas leaks and background are highly dependent on many factors, such as the wind conditions, hydrocarbon concentration, and mass emission rate. Fluctuating weather patterns further frustrate the ability to utilize OGI methods in winter conditions.

Wyoming faces unique surveying issues due to its geography and climate. The State of Wyoming is largely rural, making frequent and unexpected travel across the long distances between operational sites difficult and time-consuming which is exacerbated if survey crews are needed for simple repair verification where soap bubbles are readily available as an alternative and just as effective. Weather can be extremely unpredictable such that planned surveying travel may not be conducted as originally planned. Access to sites may be hindered by weather or logistical challenges including the difficulty in gathering all required personal to access a site at the necessary time.

Response: Concerning weather-related issues, see response to DCN EPA-HQ-OAR-2010-0505-6474, Excerpt 18. In the final rule, we are allowing the use of Method 21 with a repair threshold of 500 ppm as an alternative to OGI, which will alleviate many of the commenter's concerns about performing an OGI survey in winter months. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding this issue. We are also increasing the time to make a repair from 15 days to 30 days and allowing the use of the soap bubble alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components under certain circumstances. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more detail regarding this issue. Finally, in the final rule we have added a waiver provision for fugitive emissions monitoring at compressor stations located in certain areas of the country where average temperatures are subzero for an extended period of time. The waiver applies for only one quarter per year and is not extended to well sites, as we do not know of any areas where temperatures are subzero for six months at a time. Therefore, we believe that owners and operators should be able to meet the monitoring requirements through careful planning. See section VI.F.2.a of the preamble to the final rule for more information on this issue.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 18

Comment: EPA should allow operational flexibility instead of a blanket regulatory solution for implementation. Given the number of affected sources that will have been constructed since September 2015 until the final rule is promulgated, the proposed rule will require implementation too quickly after finalization by requiring compliance within 60 days after promulgation. The proposed implementation schedule for LDAR, cannot be accomplished within such a brief amount of time. Monitoring plans and recordkeeping systems need to be developed, equipment needs to be purchased, contracting crews need to be staffed, OGI camera operators will need to be trained, and surveys scheduled. None of these things will be completed ahead of time until there is the certainty of a final rule. Consistent with the original Subpart OOOO rulemaking for REGs and storage vessels, EPA should consider a similar compliance schedule that delays the compliance date for leak detection at well sites and production sites for 1 year plus 60 days

Response: Based on this and other comments, the EPA believes that the proposed compliance periods may be insufficient in some circumstances. For example, we proposed a compliance period of 30 days after well completion to implement a fugitive emissions monitoring program at well sites. We received comments stating that the compliance period should be measured from the point where production begins because the transition from completion to production at well sites is unpredictable and temporary completion equipment may still be on site thirty days after well completion. Another commenter indicated that production may not begin immediately after a well completion. We also recognize that owners and operators of both wells sites and compressor stations need time to complete critical steps in order to establish their program's infrastructure and build a foundation to assure continuous compliance. For these reasons, we are requiring in the final rule that the initial monitoring survey must take place within one year after publication of the final rule in the Federal Register or within 60 days of the startup of production for well sites or 60 days after the startup of a new compressor, whichever is later. See sections VI.F.1.g and VI.F.2.f of the preamble to the final rule for more detail regarding this issue.

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 22b

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 8b

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 22b

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 19b

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 19b

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 30

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 27

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 28

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 28

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 29

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 28

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 61

Comment: In addition, EPA's strict timelines for detection and repair also leave operators with little flexibility to develop a compliance plan that works best for their facilities and will stymie voluntary industry innovations to address methane leaks.

Response: We are required to determine the best system of emissions reductions (BSER) for the final rule. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion of the BSER analysis. See response to DCN EPA-HQ-OAR-2010-0505-6854, Excerpt 18 for a discussion of initial compliance. Additionally, the EPA has finalized a process for the agency to evaluate alternate or emerging technology. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 23

Comment: In sum, the implementation of any final NSPS OOOOa requires the coordinated efforts of many operators, consultants, regulators, and other stakeholders. As currently proposed, the rule requires implementation too quickly following finalization and an extended compliance date is needed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6854, Excerpt 18.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 14

Comment: Proposed NSPS OOOOa's timing for fugitive emissions requirements is problematic and unworkable for several reasons. First, upon finalization of the rule, the proposed fugitive emissions requirements would immediately go into effect for onshore affected facilities that have "commence[d] construction, modification or reconstruction after September 18, 2015." This will cover numerous sources that have been constructed or modified between September 18, 2015, and the date the Proposed NSPS OOOOa becomes effective. To require immediate compliance with fugitive emissions requirements for all these sources will be unreasonably burdensome and even unworkable for many localities in North Dakota due to the remoteness of facilities, and, depending on the time of year, weather difficulties in harsh and cold climates.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6854, Excerpts 18 and 21.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 25

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 22

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 23

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 23

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 24

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 23

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 22

Comment: EPA also did not consider the use of performance, rather than design, standards for fugitive emissions monitoring. The Methane NSPS requires fugitive emissions surveys to be performed with OGI technology. However, as discussed more thoroughly below, OGI cameras are expensive and are only one of a multitude of ways that leaks can be detected. By selecting a single form of expensive technology for detection, the Methane NSPS would require these entities to either invest in purchasing their own cameras and training personnel to use them, or hiring trained contractors to travel to their remote sites. Instead, EPA should allow small entities to demonstrate that they have company-wide compliance plans in place that detect and address leaks through a variety of means best suited to their particular sites. For small entities in states that already require monitoring and leak repair, EPA should allow compliance with those state programs to create a presumption of compliance with the Methane NSPS to ease the burden on operators.

Response: In the final rule, we are allowing the use of Method 21 with a repair threshold of 500 ppm as an alternative to OGI, which will alleviate the commenter's concern about the rule specifying a single technology to perform the surveys. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more detail regarding this issue. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 20

Comment: 1. Fugitive Emissions From Oil and Natural Gas Production Well Sites

We recommend the development and implementation of a monitoring plan with guidelines established by the EPA. We recommend the utilization of company-wide plans providing they include site specific information. Similar plans are implemented for well sites and compressor stations such as Preparedness, Prevention and Contingency - PPC plans.

2. Fugitive Emissions From Compressor Stations

We recommend the development and implementation of a monitoring plan with guidelines established by the EPA. We recommend the utilization of company-wide plans providing they include site specific information. Similar plans are implemented for well sites and compressor stations such as Preparedness, Prevention and Contingency - PPC plans.

Response: The EPA has revised the final rule by replacing the proposed corporate-wide and site-specific monitoring plan requirements with a requirement for owners or operators to develop a corporate monitoring plan for company-defined areas that would cover the collection of fugitive emissions components at the compressor stations or well sites located within that company-defined area. See section VI.F.1.h and section VI.F.2.g of the preamble to the final rule for more detail regarding this issue. We have no plans at this time to issue guidance on the preparation of monitoring plans for this rule. The requirements included in the final rule serve as a minimum outline of the information that must be included in a monitoring plan. We believe that product literature provided by OGI instrument providers, available commercial training classes and web-based training materials may afford operators with valuable information in preparing monitoring plans. We do not believe that lack of standardization through guidance will render the fugitive monitoring program ineffective. We believe that the requirements outlined in the final rule are enough to ensure that effective surveys are being performed.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 35

Comment: During the past year, Kinder Morgan has worked extensively with INGAA (who has in turn coordinated with EPA) on the development of a DI&M program that companies would incorporate as a best management practice, including, as appropriate, through development of a corporate monitoring program. This program should also be an accepted form of compliance with the proposed NSPS. Specifically, Kinder Morgan believes that any corporate monitoring program that comports with the "Directed Inspection and Maintenance Voluntary Program Elements and Procedures for Natural Gas Transmission and Storage Compressor Stations," (herein "INGAA DI&M Guidelines") submitted by INGAA to EPA in spring 2015, and conducted under a memorandum of understanding with EPA under EPA's Methane Challenge Program, satisfies the requirements of NSPS OOOOa for compressor stations in the natural gas transmission and storage sector. See Attachment C to INGAA's Comment Letter.

The INGAA DI&M Guidelines provide the structure, program elements, and procedures for development of a company-specific DI&M program that focuses on key leak sources within a facility that pose a higher probability of being "gross emitters" or "super emitters." The INGAA DI&M Guidelines (set forth in Table 1 of Attachment C to INGAA's Comment Letter) outline the key leak sources based upon information from previous studies (several are referenced above), company experience, and available information under EPA's Greenhouse Gas Reporting Program (GHGRP) and Natural Gas STAR program. Other components of the INGAA DI&M Guidelines include survey/phase-in period; adaptive management to refine facilities based on data collection; tracking of leaks; and repair of leaks, among others. Each of these components appropriately addresses requirements addressed by EPA in the Proposed NSPS OOOOa Rule.

Specifically, the INGAA DI&M Guidelines provide for incorporation of an annual survey (consistent with Subpart W) into the DI&M program. The survey methodology would be consistent with Subpart W insofar that either Method 21 or optical gas imaging ("OGI"), or a combination of both, could be used to determine the presence of a leak. Additionally, the INGAA DI&M Guidelines contain measures to track success and progress. Specifically, each company implementing the INGAA DI&M Guidelines would meet at a minimum the annual reporting requirements as outlined by the EPA's final Methane Challenge program. This would include, at a minimum, reporting of annual GHG emissions from the facilities implementing the DI&M program for that year; the percentage of company facilities implementing the INGAA DI&M Guidelines for that year; the amount of methane reductions achieved through the implementation of the INGAA DI&M Guidelines; the number of leaks identified and leaks repaired; and any additional activities and methane reductions achieved beyond the minimum DI&M requirements.

Kinder Morgan strongly supports reliance on corporate monitoring programs (and specifically DI&M) in lieu of compliance with NSPS OOOOa requirements for fugitive emissions and equipment leaks. Kinder Morgan agrees with INGAA that companies are best positioned to determine the appropriate methane reduction methodologies for their operations, and EPA should recognize the substantial voluntary efforts undertaken to date by various companies, including Kinder Morgan. INGAA and its members intend to continue to work cooperatively with EPA to respond to any outstanding questions, and ultimately ensure that EPA's criteria are met in the final INGAA DI&M Guidelines, which should make the DI&M programs an equivalent compliance option. As such, an operator should not have to collect, submit, and verify test data or otherwise comply with other unnecessary process requirements in order for EPA to recognize the alternative program (e.g., INGAA DI&M Guidelines or another alternative program, including any program implemented through a Memorandum of Understanding or other commitment under EPA's proposed Methane Challenge Program) as equivalent to any final NSPS OOOOa fugitive emissions and leak detection program. This approach is consistent with EPA's stated goal "to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions."

Kinder Morgan appreciates and supports EPA's recognition of the extensive efforts that many operators have been undertaking or have begun undertaking to voluntarily reduce emissions of VOCs and methane. Kinder Morgan strongly supports reliance on corporate monitoring programs in lieu of compliance with NSPS OOOOa requirements for fugitive emissions and equipment leaks. If EPA continues to pursue a new NSPS program, Kinder Morgan requests EPA recognize corporate fugitive monitoring programs in lieu of compliance with NSPS OOOOa requirements for fugitive emissions and equipment leaks. Though not reflected by the leak detection program proposed under the Proposed NSPS OOOOa Rule, in the preamble EPA recognizes the presence and role of "gross emitters" targeted in DI&M programs. In Kinder Morgan's extensive experience, these gross emitters have been the most efficient approach for attaining significant and relevant fugitive emissions reductions in a cost-effective manner of these gross emitters. It is of utmost importance to Kinder Morgan that EPA recognize implementation of an appropriate DI&M program as the equivalent to the NSPS OOOOa standards for fugitive emissions and equipment leaks.

Response: The EPA commends the work that has been done by this commenter and others to develop voluntary fugitive emissions monitoring programs. However, the DI&M program as described by the commenter has significant deficiencies compared to the subpart OOOOa program as finalized. Specifically, the DI&M program "focuses on key leak sources within a facility that pose a higher probability of being gross emitters or super emitters." Thus the DI&M program would not survey components that were not deemed capable of being a super emitter. We believe that this approach could allow for a large number of components to develop leaks and go undetected, leading to excess emissions that would otherwise be detected and repaired under the subpart OOOOa program. Additionally, the DI&M program as defined by the commenter calls for annual surveys. The subpart OOOOa program as finalized requires semiannual surveys of well sites and quarterly surveys of compressor stations. We believe these more frequent surveys will lead to greater methane and VOC emission reductions than the annual surveys of the DI&M program. For these reasons, we do not consider the DI&M program to be equivalent to the subpart OOOOa program and reject the commenter's request to allow compliance with the DI&M program in lieu of the subpart OOOOa requirements. In addition, regarding DI&M programs, please refer to DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 7.

Additionally, we note that we have added a procedure at §60.5398a of the final rule for owners or operators of affected facilities to apply to the Administrator for a determination of whether an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §60.5397a. Such an alternate means may include corporate fugitive emissions monitoring programs that deviate from the requirements of §60.5397a. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name: Tom Michels
Commenter Affiliation: ONE Future
Document Control Number: EPA-HQ-OAR-2010-0505-6880
Comment Excerpt Number: 5

Comment: EPA SHOULD PERMIT AND ENCOURAGE THE USE OF ALTERNATIVE METHODS OF COMPLIANCE WITH THE PROPOSED OOOOa REQUIREMENTS TO ADDRESS FUGITIVES EMISSIONS.

In the case of fugitive methane emission components at well sites and compressor stations, EPA is acting under its authority under Section 111(h) of the Clean Air Act. Section 111(h) provides authority to the EPA to promulgate a particular work practice standard only if that standard reflects "the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated)." EPA has proposed a particular leak detection and repair (LDAR) regime as the work practice standard to address fugitive methane emissions at well sites and compressor stations.

EPA's proposed requirements for addressing Fugitive Emissions at Well Sites and Compressor Stations constitute the most significant concern for ONE Future's members in the Proposed Rule, as we view the likely costs associated with these provisions as high, while the emissions reduction benefit is relatively low. We urge the EPA to provide additional flexibility to ONE Future member companies who utilize comparable or superior programs to address fugitive emissions across their assets.

EPA has the authority to allow for alternative means of emission limitation. Section 111(h) of the CAA authorizes EPA to permit the use of an "alternative means of emission limitation" if EPA finds that it will achieve a reduction in emissions "at least equivalent to the reduction" achieved by the designated work practice. To this end, we welcome that EPA has solicited comment "on criteria we can use to determine whether and under what conditions well sites and other emission sources operating under alternative fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site about fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining."

There are also strong policy rationales for this approach. EPA already has recognized, under its proposed Methane Challenge framework, the ambition of the ONE Future emissions intensity commitments and as noted earlier the Administration will need rely on voluntary programs to meet its 2025 reduction goals. Therefore, it is reasonable for EPA to support programs that are consistent with the comprehensive ONE Future commitment to optimal performance, including LDAR and DI&M programs being implemented as part of ONE Future/Methane Challenge.

Indeed, the use of existing alternative fugitive monitoring programs through approved EPA Methane Challenge programs such as ONE Future would provide strong incentives for operators to seek deeper reduction opportunities than they otherwise would pursue, including through innovative methods not necessarily covered by the prescriptive fugitive emissions standards specified in the Proposed Rule. Furthermore, by greatly reducing some of the paperwork burdens associated with OOOOa compliance, the EPA would allow operators to deploy additional capital toward R&D in emissions abatement. In this way, this approach would be consistent with Congressional intent that Section 111 would promote innovation in abatement technologies and practices.

As explained below, there are a number of currently-existing Alternative Programs that can and should qualify as "alternative methods of compliance" to the LDAR work practice standard. We believe that these alternative approaches will yield greater reductions in emissions at a lower cost.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35. We have also included language in the final rule that allows for the approval of emerging technologies for reducing fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Greg Guidry
Commenter Affiliation: SWEPI LP
Document Control Number: EPA-HQ-OAR-2010-0505-6892
Comment Excerpt Number: 7

Comment: LDAR CORPORATE Equivalency

Shell and other operators have experience with voluntary initiatives and state-mandated LDAR programs which have clearly demonstrated annual monitoring is sufficient in reducing emissions and experience supports that, over time, more frequent surveys result in negligible environmental benefit, which approaches diminishing returns. Based on our experience with such LDAR programs, Shell believes quarterly and biannual monitoring is unnecessary and not cost-effective. Implementation of a "Corporate Equivalency" concept as suggested in the proposal would support inspection frequencies justified by the maturity of the corporate program and based on the historical progress as reported and demonstrated in the successful implementation of fugitive emission BMPs in EPA's current voluntary program, Natural Gas STAR. Additionally and as an alternate means of compliance for example, participation in the proposed EPA voluntary initiative, Methane Challenge, through implementation of the associated BMP for LDAR would provide the foundation needed to support "equal or better emission reduction" and thus achieve corporate equivalency. Shell supports verification in the form of self-certification similar to that prescribed elsewhere in NSPS OOOO (40 CFR 60.5420(b)(1)(iv)). Table 3 below is a framework criteria for consideration under "Corporate Equivalency" that would support future alternatives and continuous improvement.

Response: We disagree with the commenter that quarterly and semiannual monitoring is unnecessary and not cost effective. As discussed in the TSD to the final rule, we determined that the cost of control for quarterly monitoring for compressor stations and semiannual monitoring for well sites is acceptable and that these monitoring frequencies lead to greater emission reductions than less frequent survey frequencies. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, and sections VI.F.1.a and VI.F.2.a of the preamble to the final rule for more details regarding this issue. Concerning existing voluntary and corporate fugitive emissions monitoring plans, see response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 5

Comment: Alternative Compliance Mechanism: We support the development of an alternative compliance mechanism that results in greater emissions reductions at a lower cost. The broad scope, complicated frequency, recordkeeping burden, and prescriptive timeframes for inspections will result in inefficient inspection program, likely diverting resources from current existing source programs which are not required by regulation.

- Currently, Chevron conducts inspection programs in each of our onshore production business units. We do so via a voluntary risk-based approach or due to regulatory requirements. We recommend inclusion of an alternative compliance mechanism that allows operators, particularly those with a demonstrable track record for well controlled operations, to continue to survey new and existing sources using a risk based program to determine the scope and frequency for surveys and utilizing existing programs for recordkeeping and reporting.

- Under such an alternative program, recordkeeping that includes an inspection date, estimated number of components, number of components leaking and any repairs not made within 60 days would provide all the information essential to the agency to assure compliance, without requiring companies to buy, test and assure new recordkeeping systems. Companies with systems for tracking inspections should be allowed to continue to utilize them, and make them available to inspectors as requested, instead of developing entirely new systems. These systems would also track site location, date, and number of leaks. Under this alternative compliance program companies would not be subject to other Subpart OOOOa fugitive emissions requirements such as site specific plans, weather tracking, and photos.

- A company-wide plan detailing training requirements and standards for surveys could be provided to EPA. An annual report outlining the total number of sites inspected and the number of leaks found (total and as a proportion of estimated components) could also be submitted. We believe the frequency, scope, and recordkeeping contained in the 9/18 proposal would be a major disincentive to companies to continue voluntary programs that cover both new and existing sources, ultimately resulting in fewer emissions reductions and more resources dedicated to recordkeeping.

- Please see ATTACHMENT A for suggested mechanisms for an alternative compliance approach.

ATTACHMENT A

Set forth below are three of the potential options for supporting an alternative compliance approach under the terms of the Clean Air Act. We urge EPA to include one or more of these options in the final rule. As EPA acknowledges in the preamble to the proposed rule, many owners and operators have already implemented state and corporate-wide fugitive emissions reduction programs, which evolved based on either state regulatory requirements or programs that companies have developed as responsible corporate citizens to use innovative and often cutting-edge approaches to reduce leaks.

Corporate programs efficiently target and detect leaks based on owner or operator experience and, at the same time, achieve equal or greater emissions reductions than would be achieved through this rulemaking without the complex, administratively burdensome, and very costly compliance program set forth in the proposal. As it stands, we anticipate that the administrative burden imposed through the federal LDAR provisions will drastically impact the cost of maintaining our fugitive emissions program without providing any additional emissions reductions.

There is considerable precedent for inclusion of alternative compliance mechanisms in EPA rules. For example, in some instances, EPA has adopted as an "alternative standard" similar state or local rules. In other instances, EPA has adopted an "alternative means of emission limitation" that allows sources or even equipment manufacturers to apply for an equivalency—based on emissions—for an alternate standard. In other instances, EPA has created a regulatory "off-ramp" for sources that implement pollution control requirements that would be required by a rule and allow them to document the controls, but not be subject to burdensome recordkeeping and reporting requirements. Still in other cases, EPA has allowed compliance with other federal rules to satisfy a particular rule's obligations in order to avoid duplicative reporting and recordkeeping regimes.

We appreciate EPA's recognition of these concerns by soliciting comment on such an approach in the preamble to the proposal. We understand the need for any alternative standard to be enforceable and welcome the opportunity to engage in a dialogue with EPA regarding the appropriate mechanisms for monitoring, reporting, recordkeeping, and enforceability of any of these alternative compliance options.

1. Alternative Standard Relying on State and Voluntary Programs Pursuant EPA's Authority Under Clean Air Act Section 111(h)(1)

Section 111(h)(1) of the Clean Air Act allows EPA to prescribe a performance standard that reflects the best technological system of continuous emission reduction if it is "not feasible to prescribe or enforce a standard of performance." Relying on Section 111(h)(1), EPA could designate an alternative standard by which owners and operators could comply with the requirements in the rule. This approach would avoid the inefficiencies associated with overlapping state and voluntary programs by designating them as alternative standards. Moreover, owners and operators could maintain existing programs and ensure that resources are focused primarily on emissions reduction.

We suggest that EPA benchmark the standard against the 1.18% baseline leak rate assumed in EPA's analysis. For purposes of this proposal, EPA estimates that its fugitive emissions program will achieve an 80 percent reduction level with a quarterly monitoring program, 60 percent reduction level with a semi- annual monitoring program, and a 40 percent reduction level with an annual monitoring program. We anticipate the EPA can make the appropriate finding of efficacy for those programs that achieve or exceed emissions reductions from this benchmark.

The efficacy of this program can be adequately demonstrated. Chevron's emissions program has already achieved leak rates <u>far below</u> those anticipated through implementation of the federal LDAR requirements: At present, measured leak rates range from 0.04 to 0.16 percent of components leaking.

2. Alternative Compliance Relying on State and Voluntary Programs Pursuant to EPA's Authority Under Clean Air Act Section 111(h)(3)

Clean Air Act Section 111(h)(3) provides that EPA may authorize the use of an "alternative means of emission limitation" that will achieve an equivalent reduction in emissions "after notice and opportunity for public hearing." Pursuant to Section 111(h)(3), the agency could include a provision that would allow owners and operators to petition EPA to designate their state or corporate fugitive emissions programs as alternative means of emission limitation, conditioned on a finding of equivalency.

As discussed above, EPA could base the finding of equivalency on the 1.18% leak rate assumed in EPA's analysis and the anticipated emissions reductions EPA expects to achieve through this rulemaking.

We note that this approach can be combined with the other approaches included in this Attachment (just as EPA did in Subpart Ja of the NSPS rules for refinery flares) to provide the greatest flexibility for owners and operators to demonstrate the equivalency of existing programs, thus streamlining compliance while achieving the same ends EPA seeks in the proposed rule.

3. Applicability Criteria Pursuant to EPA's Authority Under Clean Air Act Section 111(h)(1)

A third option available to EPA is to include a provision similar to the approach used in Subpart OOOO regarding hydraulic fracturing, in which EPA created a regulatory off-ramp for sources that were doing green completions. Here, EPA could find that facilities that have implemented and are complying with state or corporate fugitive emissions programs that achieve the same emission reductions as the federal program are not affected facilities. As with the other options outlined above, this provision would allow owners and operators with successful existing LDAR programs in place to continue to advance these programs and, at the same time, achieve the emission reductions EPA anticipates will be achieved through the federal LDAR program.

Here again, EPA could benchmark the performance standard by which applicability of the LDAR provisions would be determined according to the 1.18% leak rate assumed in EPA's analysis and the anticipated leak rates EPA expects to achieve through this rulemaking.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35. See response to EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for more information on potential emission reduction from fugitive monitoring.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 22

Comment: We appreciate the opportunity to comment on corporate fugitive monitoring plans. We stress the proposed rule is soliciting comment on a work practice, which should not be treated as a performance standard for compliance purposes. Instead, the proposed rule should be modified to accept corporate-wide fugitive emissions monitoring plans in lieu of further monitoring per OOOOa. Such corporate plans have been implemented for years by many of the leading companies in the industry, and these plans act as prime examples of industry taking the lead on improving operations while providing environmental benefits. Now is not the time to stifle or punish such efforts by imposing a prescriptive, one-sized fits all program that effectively sends these companies back to the drawing board. The Alliance believes the choice to accept a corporate-wide plan is not merely a minor point. Rather, depending on how the final rule treats this issue, it will effectively send one of two signals to the regulated community: a positive message that it pays to do the right thing or a negative message that no good deed goes unpunished.

By way of example, we received input from our members on some current corporate fugitive monitoring plans.

- Powder River Basin, Wyoming (WY): Operator conducts quarterly thief hatch inspections (performed by third-party consultants) and OGI camera monitoring. WY permits require quarterly audio/visual/olfactory (AVO) and annual OGI or Method 21.
- Williston Basin, North Dakota (ND): Operator conducts annual OGI camera monitoring and repairs.

In some instances, operators will visit locations on a daily basis. These visits almost always include general audio/visual/olfactory (AVO) monitoring, with any leaks noted and repairs made. Operators also are implementing or developing preventative maintenance programs around the country. We raise these examples so that EPA can understand what these corporate voluntary programs may look like, and to solicit feedback from EPA on the sufficiency of these programs.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 26

Comment: AGA Urges EPA To Consider Revisions That Promote Consistency With Other EPA Programs.

AGA appreciates EPA's attempt to minimize the burden on regulated parties by seeking comment on how the Agency can avoid duplication or conflicts with other existing regulations. Several examples are discussed in these comments (e.g., delay of repair provisions), and reiterated below.

EPA should consider alternative compliance options identified through the Natural Gas STAR program, including DI&M for addressing compressor station equipment leaks and condition-based maintenance for reciprocating compressor rod packing.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35, for information related to DI&M. See section VIII.C.3 of the preamble of the final rule for a discussion on condition based maintenance.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 23

Comment: Operators currently engage in voluntary corporate monitoring programs

We appreciate the opportunity to comment on corporate fugitive monitoring plans. We stress the proposed rule is soliciting comment on a work practice, which should not be treated as a performance standard for compliance purposes. Instead, the proposed rule should be modified to accept corporate-wide fugitive emissions monitoring plans in lieu of further monitoring per NSPS OOOOa. Such corporate plans have been implemented for years by many of the leading companies in the industry, and these plans act as prime examples of industry taking the lead on improving operations while providing environmental benefits. Now is not the time to stifle or punish such efforts by imposing a prescriptive, one-size-fits-all program that effectively sends these companies back to the drawing board. And if voluntary programs are viewed by EPA as appropriate for the agricultural sector, a larger emitter of methane by any reasonable measure, they should certainly be equally available to the oil and natural gas upstream and midstream sectors.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 37

Comment: TXOGA Supports the Concept on Which EPA Solicits Comment Regarding Providing an Alternative Compliance Approach for Sources Complying with State or Corporate LDAR Programs.

EPA correctly solicits comment on criteria the agency can use to determine whether corporate fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions for purposes of establishing "alternative methods of compliance or otherwise provid[ing] appropriate regulatory streamlining." TXOGA supports the rationale behind the agency's request for comment and recommends that EPA include an alternative compliance mechanism in the final rule.

Alternative compliance will be a critical component of the final rule. As EPA recognizes, many owners and operators have already implemented state and corporate-wide fugitive emissions reduction programs. These programs have evolved based on either state regulatory requirements or programs that companies have developed as responsible corporate citizens to use innovative and often cutting-edge approaches to reduce leaks. Furthermore, corporate programs often better target and detect leaks based on owner or operator experience and, at the same time, achieve the same ends EPA seeks without the complex and administratively burdensome compliance program set forth in the EPA's proposal. EPA should encourage corporate programs that achieve the leak performance aims of the NSPS in recognition of the fact that companies that have implemented programs across their facilities have made substantial investments well in advance of any regulatory requirements and that it will be extremely problematic to suddenly shift gears and implement a different program. Thus, companies with systems for tracking inspections should be allowed to continue to utilize them, and make them available to inspectors as requested, instead of developing entirely new systems. Like the proposal, these systems would also track site location, date, and number of leaks, so the leak rate aims of the NSPS will be met.

An alternative compliance option would allow owners and operators to advance existing LDAR programs, focusing energy and resources on emission reductions. Moreover, owners and operators are more likely to adopt LDAR programs in advance of the compliance date – assuming EPA appropriately adopts the one-year compliance extension TXOGA recommends in Section IV(C(8)(A), *infra* – if there is an opportunity to streamline requirements and ease the administrative burden of compliance. And, by allowing these sound programs to continue, EPA will ensure that companies that are applying them to both new and existing sources (which is typical) will continue to implement such programs for existing sources.

There are at least three potential options for supporting an alternative compliance approach under the terms of the Clean Air Act. TXOGA requests that EPA to include all of these options in the final rule. As EPA acknowledges in the preamble, the programs that pre- dated EPA's proposed regulation evolved based on either state regulatory requirements or programs that companies have developed as responsible corporate citizens to use innovative and often cutting-edge approaches to reduce leaks.

There is considerable precedent for inclusion of alternative compliance mechanisms in EPA rules. For example, in some instances, EPA has adopted as an "alternative standard" for similar state or local rules. In other instances, EPA has adopted an "alternative means of emission limitation" that allows sources or even equipment manufacturers to apply for an equivalency—based on emissions—for an alternate standard. In other instances, EPA has created a regulatory "off-ramp" for sources that implement pollution control requirements that would be required by a rule and allow them to document the controls, but not be subject to burdensome recordkeeping and reporting requirements. Still in other cases, EPA has allowed compliance with other federal rules to satisfy a particular rule's obligations in order to avoid duplicative reporting and recordkeeping regimes.

As it stands, the proposal will disproportionately increase the costs of compliance for those owners and operators that have already implemented fugitive emissions programs. Consequently, TXOGA urges EPA adopt the following alternative compliance options, which are consistent with EPA's stated intent to continue to encourage corporate-wide voluntary efforts to achieve emissions reductions and streamline regulatory compliance. There are at least three ways the agency could rely on these programs as a compliance alternative:

- Include an alternative standard relying on state and voluntary programs per CAA Section 111(h)(1).
- Provide for alternative compliance relying on state and voluntary programs per Section 111(h)(3).
- Create applicability criteria relying on requirements per Section 111(h)(1).

EPA Should Include an Alternative Standard Relying on State and Voluntary Programs Per CAA Section 111(h)(1) or an Alternative Compliance Option Under the Rule.

Under the first approach, EPA would include a provision in the final rule that designates an alternative standard of performance under CAA Section 111(h)(1), which allows EPA to prescribe a performance standard that reflects the best technological system of continuous emission reduction if it is "not feasible to prescribe or enforce a standard of performance." In addition, EPA can avoid the inefficiencies associated with overlapping state programs by incorporating these programs by reference into the final rule, designating them as satisfactory alternatives to compliance with the federal program.

EPA did this, for example, in Subpart Ja, Standards of Performance for Petroleum Refineries with respect to Bay Area Air Quality Management District flare minimization. Specifically, Section 60.103a(g) provides:

> An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to [EPA].

Any fugitive emission monitoring program required by rule, whether or not approved as part of a SIP, that is legally and practically enforceable by a state or local administrative authority should be considered equivalent.

Alternatively, EPA could consider periodic publication of a list of state or local rules, permits by rule, general permits or other permits or programs that would be approved as an alternative to meeting fugitive emissions standards for well sites and compressor stations. EPA already has such a program where it lists combustion control devices that have been tested under §60.5413(d).

TXOGA also supports a provision that allows an owner or operator to elect to voluntarily comply with a state program at all affected facilities if subject to the state regulations at other facilities. This provision would streamline the compliance process for regulated entities and avoid creating a "patchwork" of complicated, and sometimes conflicting, federal and state regulations with which an entity must comply.

This provision could include the required elements of an alternative compliance program that would serve as an alternative standard. For purposes of this proposal, EPA assumes a 1.18 percent component leak rate and estimates that its fugitive emissions program will achieve an 80 percent reduction level with a quarterly monitoring program, 60 percent reduction level with a semi-annual monitoring program, and a 40 percent reduction level with an annual monitoring program. EPA could benchmark an alternative standard off this leak rate and the anticipated emissions reductions EPA expects to achieve through this rulemaking. EPA can readily make a finding of efficacy for those fugitive emissions programs that achieve or exceed this performance requirement.

TXOGA appreciates the need for any alternative standard to be enforceable and welcomes the opportunity to engage with EPA on the details of the elements of monitoring and enforceability.

EPA Should Provide for Alternative Compliance Relying on State and Corporate Programs Under CAA Section 111(h)(3).

CAA Section 111(h)(3) provides that, "after notice and opportunity for public hearing," EPA may permit the use of an "alternative means of emission limitation" that will achieve an equivalent reduction in emissions of any air pollutant. Accordingly, relying on Section 111(h)(3), EPA should include a provision in the final rule by which an company could apply to have a fugitive emissions program designated as an alternative means of emission limitation. Should EPA adopt this approach, it should provide that any fugitive emissions program that has equivalent or better performance, based on the 1.18% leak rate assumed in EPA's analysis and anticipated reductions expected, achieves the same performance (*i.e.*, 1.18 percent leak rate and anticipated emission reduction resulting from this rulemaking). TXOGA is open to engaging in a dialogue with EPA regarding the required documentation for owners and operators to demonstrate equivalency as well as mechanisms for enforcement and streamlined approval. We also request that EPA model the concept set forth in NSPS Subpart Ja, which provides in Section 103a(j)(5) that *manufacturers of equipment* used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements for the standard. Under this provision, a manufacturer can obtain a nationwide determination so that each individual source that wants to use the manufacturer's equipment is not required to "apply" with the attendant procedural requirements. A similar approach could be used so that a company with operations in numerous states could have its program sanctioned by EPA and individual sites could then use that program without further approval by the Agency.

EPA Should Also Create Applicability Criteria Relying on Requirements Under CAA Section 111(h)(1).

A third option available to EPA is to include a provision similar to the approach used in Subpart OOOO regarding hydraulic fracturing, in which EPA created a regulatory off-ramp for sources that were doing green completions. Here, EPA could find that facilities that have implemented and are complying with state or corporate fugitive emissions programs that achieve the same emission reductions as the federal program are not affected facilities. As with the other options outlined above, this provision would allow owners and operators with successful existing LDAR programs in place to continue to advance these programs and, at the same time, achieve the emission reductions EPA anticipates will be achieved through the federal LDAR program. Here again, EPA could benchmark the performance standard by which applicability of the LDAR provisions would be determined according to the 1.18% leak rate assumed in EPA's analysis and the anticipated leak rates EPA expects to achieve through this rulemaking.

A further option would be for EPA to include a provision like that included in Subpart OOOO, in which EPA created a regulatory "off-ramp" for sources that do green completions. In the context of Subpart OOOOa, EPA could find that facilities that have implemented and are complying with state or corporate fugitive emissions programs that achieve the same leak rate goals as intended by the federal program are not affected facilities.

This provision would allow owners and operators with successful existing LDAR programs in place to continue to advance these programs. TXOGA welcomes the opportunity to engage in a dialogue with the agency regarding the appropriate recordkeeping and reporting requirements.

In sum, TXOGA urges EPA to consider including an alternative compliance option in the final rule. Precedent as well as a host of sound policy reasons exist to support adopting all of the approaches outlined above and TXOGA is ready to engage in a dialogue with EPA regarding these and other options to support continued implementation of existing corporate programs. Indeed, the broad scope, complicated frequency, recordkeeping burden, and prescriptive timeframes for inspections outlined in the proposed rule for new, modified, and reconstructed sources will result in an inefficient inspection program, likely diverting resources from current existing source programs that companies are implementing even though they are not required by regulation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35. See response to EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for more information on potential emission reduction from fugitive monitoring. Additionally, we note that §60.5397a is a work practice standard based on a multifaceted monitoring program, not an emissions limit, so equivalency is a more complicated matter. Therefore, we cannot make blanket statements that just because a facility is subject to another set of fugitive emissions monitoring standards, that source does not have to comply with §60.5397a of the final rule. See section VI.K of the preamble to the final rule for more information on provisions for equivalency determinations for monitoring programs.

Commenter Name: Tom Michels
Commenter Affiliation: ONE Future
Document Control Number: EPA-HQ-OAR-2010-0505-6880
Comment Excerpt Number: 8

Comment: Create a framework to employ alternative methods of compliance with EPA's Fugitive Emissions standards. Many leading companies, including ONE Future members, have already undertaken significant measures to reduce their methane emissions by via alternative LDAR and DI&M programs. These programs are typically applied across operators US assets and applied to both new and existing facilities. ONE Future companies recognize the importance of commercial performance and efficient deployment of capital and resources to achieve the greatest reductions. Typically, existing facilities have higher emissions than new facilities. New facilities in the natural gas sector are already designed with the newest and most advanced technology.

We urge the EPA to permit and encourage companies to adopt alternative methods of compliance with the OOOOa Fugitive Emissions requirements, as provided for under CAA § 111(h)(3), provided the programs meet the following criteria:

1. The Alternative Fugitive Emissions Monitoring Program ("Alternative Program") is employed under the EPA Methane Challenge's Best Management Practice (BMP) or ONE Future programs thereby ensuring that the program provides ample performance data.
2. The Alternative Program includes a process for conducting leak surveys, identifying leaking components/equipment, and repairing leaking components/equipment.
3. The Alternative Program either takes the form of a Directed Inspection & Maintenance Program (DI&M), or includes recordkeeping and reporting requirements that may be used to assist the firm to develop such a program. A DI&M allows each operator to determine where inspections should take place based on their unique, intimate knowledge of their operating assets. DI&M is a well-established, EPA-recognized tool for detecting, prioritizing and repairing fugitive emissions in a cost-effective manner. It provides operators with the flexibility to utilize the knowledge of their operations to identify the major leaks, which historically have been found to emanate from a small number of sources.
4. The Alternative Program includes Audible, Visual, Olfactory leak survey during regular well pad and compressor station facility visits as part of routine operations (i.e., standard operating practices).
5. The Alternative Program includes the use of an optical gas imaging or infrared camera and/similar devices to conduct "instrument" leak detection surveys at well pads and compressor stations.
6. The Alternative Program requires an instrument leak detection survey of new wells and new compressor stations within 180 days of commencing operation. The subsequent survey frequency should not be arbitrarily fixed at a semi-annual basis as noted below.
7. The Alternative Program specifies timelines for when repairs need to be completed and if needed a re-survey.
8. The Alternative Program should specify training requirements and qualifications for employees and contractors as it relates proper operations of the instruments, understanding of the program and process and field training with the use of instruments.

The final rule should establish provisions for companies to submit Alternative Programs that meet the above criteria. The NSPS rules should allow for such "alternative or custom plans." As an example, NSPS Subpart GG requires fuel gas sulfur content monitoring for certain turbines. However, companies may submit a custom plan and request revisions to the frequency of the monitoring and revisions to the monitoring locations. Over time, EPA has approved many custom monitoring plans that removed the monitoring from each turbine location to key locations along the pipeline.

Alternative LDAR or DI&M programs undertaken as part of the EPA Methane Challenge (BMP or ONE Future) are deemed equivalent to the EPA NSPS OOOOa standards and can be employed at any new or modified affected fugitive emissions facility immediately on finalization of the rule. This ensures a streamlined and predictive process for current participants in the ONE

Future program. We highly recommend that EPA "jump starts" the process through the Methane Challenge program and that EPA develops a "White Paper" or other provisions to develop template Alternative Programs (e.g. see SWN SMART LDAR Best Practice submitted to ECOS) to incorporate these approval of Alternative Programs currently undertaken by ONE Future members.

Enforcement of the Alternative Program should be limited to affected facilities under the OOOOa Rule. Existing sources that the company monitors employing the Alternative Program should not be subject to any enforcement actions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Todd Parfitt, Director
Commenter Affiliation: Wyoming Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2010-0505-6993
Comment Excerpt Number: 7

Comment: Determining equivalent fugitive emissions monitoring plans. FM plans are, by the nature of their implementation, complex and site-specific. The EPA should not take a narrow approach by selecting only a limited set of criteria by which to determine whether FM plans are equivalent. As mentioned earlier, AQD takes a site-specific approach to determining appropriate FM requirements, which tailors the monitoring requirements to the anticipated impact on the environment. The EPA should use worst case fugitive emissions as a criteria for evaluating FM plans and for establishing the requirement to perform FM. If the EPA established a performance standard of conducting a FM plan for affected well sites with, for example, six tons per year or more of fugitive VOC emissions, then states with minor NSR permitting programs that apply BACT would have the opportunity to require additional monitoring if such monitoring is technically achievable and economically reasonable. Without establishing an emissions threshold, equivalency is evaluated solely on work practice standards that may or may not have an equivalent effect on reducing emissions. Establishing an emissions threshold also provides an incentive to industry to develop better technology, such as low emitting valves. Installation of such equipment could result in lower fugitive VOC emissions and as a result, potentially less FM monitoring. The EPA could use an emissions threshold for fugitive emissions in the same manner as it uses a threshold for VOC emissions from storage vessels and establish NSPS OOOO requirements for well sites with six tons per year or more of fugitive VOC emissions. Well sites with less than six tons per year of fugitive VOC emissions would be subject to FM plans in states that have implemented such requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc.,

(C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 13

Comment: We recommend the EPA exercise due diligence in defining alternative methods of compliance and regulatory streamlining in regards to corporate monitoring plans meeting NSPS standards for well site fugitive emissions. Please be mindful, our family homes and our children's schools are often measureable feet from well sites where harmful VOCs are released into our air.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 40

Comment: Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

1. Fugitive Emissions From Well Sites

We recommend establishing a regular quarterly or semi-annual review as one effective option to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). This will ensure that goals are being met and hopefully create a better environment for those who live or attend school near well sites.

2 Fugitive Emissions From Compressor Stations

We recommend establishing a regular quarterly or semi-annual review as one effective option to address enforceability of such alternative approaches (i.e., how to assure that these compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). This will ensure that goals are being met and hopefully create a better environment for those who live or attend school near compressor stations.

Response: The EPA has not defined a regular review period for alternate means of emissions limitations. We believe that we are requesting enough information up front to determine whether each request is equivalent to the finalized standards. However, should we determine that a regular review period is necessary, this can be included in the approval of the request.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 20

Comment: Modification of the Collection of Fugitive Emissions Components at Well Sites and Compressor Stations. EPA is soliciting comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). EPA is also soliciting comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites and compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). CONSOL would encourage the EPA to consider allowing alternative approaches for compliance such as membership and certification through organizations such as the CCSD. The goal of the CSSD Performance Standards is to ensure that each performance standard (including the Air Performance Standards) requires a level of environmental performance that exceeds the regulatory minimums established by the states and the federal government. CONSOL believes that certification through a non-profit organization such as the CSSD would meet the equivalent of the NSPS standards for well site fugitive emissions as an alternative method of compliance and would provide regulatory streamlining. Enforcement could be established through the CSSD auditing process by submittal of the CSSD certification documentation.

Response: We appreciate the information provided by the commenter. As discussed in our response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35, owners or operators may apply to the Administrator for a determination of whether an alternative monitoring program qualifies as an alternative means of emissions limitation.

See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15, for information on third-party auditing.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 84

Comment: How would the EPA or states enforce these rules? Companies who do not comply with requirements should incur serious fines and penalties.

Response: The final rule includes compliance requirements for all affected facilities. These requirements include specific monitoring, recordkeeping and reporting requirements that the regulatory agency can use to determine compliance. If a violation is found, it would then be up to the regulatory agency to determine appropriate penalties as allowed under local, state, and federal laws.

Commenter Name: P. DeMarco
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5167
Comment Excerpt Number: 8

Comment: Corporate voluntary compliance protocols are inadequate to protect the public health and safety.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: D. Weiss
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5289
Comment Excerpt Number: 5

Comment: While the proposed regulations require the oil and gas industry to detect leaks and repair them, there is no uniformity in how this is done or how it is reported. This leaves too much wiggle room for the industry to gloss over important indicators and does not allow the development of a continual quality improvement program that could be used to develop best practices and a set of tools with which to compare across different geographic sectors or between like size companies and operations. Self-reporting has not worked in the past and all surveys should be conducted by the DEP utilizing quality improvement guidelines and indicators developed by the EPA.

Response: The EPA disagrees that there is no uniformity in the fugitive emissions monitoring provisions and reporting requirements. On the contrary, the rule as finalized is very specific in how to conduct the monitoring survey and resurvey of repaired components. The final rule is also explicit in the records that must be kept and reports submitted electronically to the EPA. We also disagree that self-reporting is ineffective. The EPA has utilized self-reporting in conjunction with inspections by local, state and federal agencies with great success. We also disagree that state agencies should perform the surveys because these agencies lack the resources that would be required to conduct the surveys.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 64

Comment: EPA's Proposed NSPS OOOOa Rule requires an unprecedented corporate-wide fugitive emissions monitoring plan for affected well sites and compressor stations, despite very detailed requirements set forth in the extensive and comprehensive rule as proposed. Specifically, EPA proposes that a corporate-wide fugitive emissions monitoring plan cover eight (8) different components. EPA's corporate monitoring plan institutes duplication of the regulation requirements, unnecessary process and paperwork, compliance concerns, and increased expense without any additional air quality benefits to be gained, particularly when combined with the third-party verification program and audit program (described in Sections V(G)(6)(c) and V(G)(6)(d), respectively). In particular, the corporate-wide fugitive emissions monitoring plan proposal suffers from several significant flaws.

First, the majority of items required to be addressed in the plan are specifically set forth in the rule itself and EPA has not justified nor provided a reasonable explanation for imposing additional costly procedural requirements merely to mirror those provisions stated within the rule itself. Examples of such provisions required in the fugitive emissions monitoring plan include frequency of surveys, techniques for determining emissions, types of equipment to be used to determine emissions, timeframes and process for repair, processing for verifying repair, recordkeeping and length of recordkeeping, to name but a few.

Second, the proposed rule as crafted provides much-needed flexibility in a number of areas, allowing operators some discretion in implementation of an otherwise costly, extensive, and comprehensive command and control program. The requirement to incorporate certain requirements into the fugitive emissions monitoring plan for the entire company eliminates both the flexibility necessary between facilities but also the flexibility needed on a case-by-case basis. There is no reason to try to force companies to dictate, from the outset, such items as manufacturer and model number of fugitive emission detection equipment to be used, technique for determining fugitive emissions, etc. Though the site-specific monitoring plan appears to allow for site-specific deviations from the corporate fugitive emissions monitoring plan, such a framework sets up a company for failure in the event that it utilizes different technologies on different sites without acknowledging such deviations or needs to make such deviations or revisions under individual circumstances (due to equipment availability, weather conditions, or other ever-changing factors). Importantly, both the corporate fugitive emissions plan and the site-specific plan fail to account for the fact that many companies will have consultants assisting or conducting these surveys; however, it will likely not be the same consultant for all facilities, particularly in different areas, and those consultants will have different equipment, different procedures, and different methodologies. Thus, the stringent requirement to have both a corporate and site-specific plan both limits and complicates the use of third-party contractors. Again, none of these additions provide enhanced air quality benefits as all of the requirements are, or can be, adequately set forth in the regulations—just as they are in all other similar programs.

Third, many of the items EPA seeks for inclusion in the corporate fugitive emissions monitoring program are items or specifications that Kinder Morgan expects would be provided as part of the manufacturer's specifications, operating manuals, and other materials traditionally and commonly provided by the manufacturer of equipment used in the oil and natural gas industry. For example, upon receipt of its FLIR GF3xx series camera, Kinder Morgan also received a 194-

page "User's Manual" that addresses in detail the technical specifications of the equipment, maintenance requirements, process descriptions, and other technical data. Thus, maintaining the manufacturer's specification document regarding the relevant equipment on-site should be adequate.

Fourth, a corporate monitoring plan is unnecessary as EPA's 2008 "Alternative Work Practice to Detect Leaks From Equipment" already details specific work practice requirements for equipment leak and detection (hereinafter, "AWP Standards"). The AWP Standards appropriately allow for the necessary flexibility to implement a cost-effective program:

> In promulgating such standards, we are not required to mandate a single work practice applicable to all sources in a source category but may instead provide several alternative work practice (AWP) options. Indeed, the United States Court of Appeals for the District of Columbia Circuit has indicated that EPA may provide sources with multiple work practice compliance options if EPA demonstrates that at least one of these options is cost-effective and expressly provides for the alternative in the standard.

Thus, we request EPA not further duplicate existing work practice requirements that Kinder Morgan and others currently implement.

In short, corporate fugitive monitoring plans are unnecessary, duplicative of existing requirements, and overly burdensome. Thus, Kinder Morgan proposes striking all of EPA's proposed Section 60.5397a from the Proposed NSPS OOOOa Rule.

Response: Although the EPA disagrees with the points made by the commenter concerning the monitoring plan, in the final rule we have simplified the plan requirements and are now specifying a company-defined area plan in place of both the corporate plan and site-specific plan. In doing so, we have revisited the elements that are required in the monitoring plan. We note that the elements required in the monitoring plan are necessary to judge the quality of the fugitive emissions survey, in light of the fact that the EPA does not have a standard method for use of OGI. While the AWP did not require a corporate monitoring plan, the AWP requires an annual Method 21 survey in conjunction with the periodic OGI surveys. We are not requiring owners and operators in this final rule to use Method 21 annually if they choose to use OGI to monitor for fugitive emissions. Additionally, owners and operators are not prevented from deviating from the monitoring plan; the deviations must merely be noted in the annual report. See sections VI.F.1.h and VI.F.2.g of the preamble to the final rule for more detail regarding this issue. Concerning existing monitoring programs, see response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)

Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 8

Comment: Custom Plan Option

The proposed rule sets forth a prescriptive corporate-wide fugitive emissions monitoring plan and alternative site-specific fugitive emissions monitoring plan which include initial instrument survey, semi-annual surveys, leaking component/equipment repair deadlines, and robust recordkeeping and reporting elements. Although this establishes a baseline road map for those implementing a fugitive emissions monitoring program for the first time, it penalizes those whom have been implementing a fugitive emissions monitoring program (aka LDAR) on a voluntary basis. In addition, the prescriptive nature of the rules does not allow companies to seek alternatives to the programs such as frequency of surveys, instrumentation used in the surveys, or implementation of a more mature Directed Inspection and Maintenance Program (DI&M).

Requiring a fugitive emissions monitoring program in this prescriptive manner, prevents companies from implementing efficiency measures that lower the actual cost of the fugitive emissions control measures. By coordinating monitoring surveys based on well site and compressor station routes, a company may be able to significantly decrease the travel time involved in conducting the survey. As an example, an Operator may be able to coordinate several surveys with a travel route from one location to the next that minimizes travel time. However, if that flexibility is removed, it is quite probable that the travel time to the "site" could easily exceed the time to conduct the physical instrument (OGI) survey. Under the "Custom Plan" provision a company could propose a more reasonable time frame for conducting surveys based on travel time between affected sources well sites/compressor station sites and minimize cost.

The proposed rules prescriptively requires the use of an OGI or Method 21 instrument to conduct the instrument surveys. Although SWN supports the use of these instruments, the rules prevent the use of other instruments that may be better for identifying leaks. Although this is addressed in more detail below (Alternative Monitoring and Measurement Devices), the "Custom Plan" provision would allow companies to implement alternative monitoring and measurement devices that achieve same or even better leak detection results. The proposed rule specifies an initial instrument survey followed by semiannual surveys. The proposed rule also provides mechanism for decreasing the instrument surveys to annual based on a less than 1% component leak rate and increasing the instrument surveys to quarterly based on a greater than 3% component leak rate. Although we address survey frequencies below, we believe that under a "Custom Plan" a company could define various parameters for decreased or monitoring surveys based on actual survey observations/results. This could include items such as percentage of leaking components, an Emissions Intensity Level (emissions/production), or observations identifying the prime emitting sources (e.g. storage tank thief hatches) .

Finally, this provides a pathway for companies to transition from a fugitive emissions monitoring program to a Directed Inspection and Maintenance program (DI&M) as their program "matures". The DI&M program would allow each operator to determine where inspections should take place based on their unique, intimate knowledge of their operating assets. DI&M is a well-established and EPA recognized tool for detecting, prioritizing and repairing fugitive emissions in a cost-effective manner. It provides operators with the flexibility to utilize the knowledge of their operations to identify the major leaks, which historically have been found to emanate from a small number of sources.

The final rule should establish provisions for companies to submit "Custom Plans" which meet the core intent of the federal requirements (which should be to find and fix fugitive component leaks). These "Custom Plans" could be at a corporate-wide, company-wide, area-wide, or site-specific level.

SWN notes that NSPS rules allow for such "custom plans". As an example, NSPS Subpart GG turbines are/were subject to fuel gas sulfur content monitoring. However, companies could submit a custom schedule and request revision to the frequency of the monitoring and monitoring locations (see 60.334(i)(3)). Over time, many custom monitoring plans were approved that removed the monitoring from each turbine location to key locations along the pipeline.

We believe that a similar approach could be applied to the fugitive emissions components at well sites and compressor sites and since the program is implemented under existing NSPS provisions would still be enforceable. However, the timelines for reviewing and approving such "Custom Plans" should be streamlined on the front end. SWN would work with EPA under "White Paper" or other provisions to develop template fugitive emissions programs to streamline the timeline(less than 6 months) for "Custom Plan" approval.

Recommendations:

Based on the comments above, SWN recommends that EPA include provisions in the rule similar to the NSPS GG 60.334(i)(3) "custom schedule" provisions which would allow companies to submit "Custom Plans" for approval. Below is suggested language for inclusion of the "Custom Plan" provision in the proposed rule.

<u>60.5397a (m) Operators may develop custom fugitive emissions monitoring plans for implementation at affected source ·well sites and compressor station sites. The custom fugitive emissions monitoring plan should contain the following core elements.</u>
<u>(1) Area of coverage (e.g. corporate-wide, company-wide, area-wide, site-specific)</u>
<u>(2) Frequency for conducting survey(s)</u>
<u>(3) Technique for determining fugitive emissions (i.e. instrumentation to be used)</u>
<u>(4) Leak thresholds (e.g. observation of plume in OGJ, 500 ppm using Method 21)</u>
<u>(5) Repair provisions</u>
<u>(6) Recordkeeping provisions</u>
<u>(7) Reporting provisions</u>
<u>(8) Training Requirements</u>

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 5.

Commenter Name: Douglas E. Jones, Chairman
Commenter Affiliation: Pennsylvania Grade Crude Oil Coalition (PGCC)
Document Control Number: EPA-HQ-OAR-2010-0505-6239
Comment Excerpt Number: 6

Comment: In addition, Pennsylvania has instituted a Mechanical Integrity Assessment program. Conventional operators must comply with the requirements of the program and furnish reports to the Department of Environmental Protection. Having an additional federal reporting requirement would be burdensome, costly and redundant for conventional operators.

The PGCC requests an exemption from fugitive emissions testing and reporting for stripper wells, low pressure wells and conventional wells. The Pennsylvania Mechanical Assessment program should be sufficient.

Response: We disagree that a state program, without further analysis, should be deemed sufficient or equivalent to the requirements of the final rule. We also disagree that stripper wells, low pressure wells, and conventional wells should be excluded. Our data indicates that fugitive emission rates are not necessarily directly related to the amount of oil or natural gas flowing through the equipment at a well site. Concerning existing programs, see response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 18

Comment: The required use of OGI fugitive emission monitoring will in effect remove the opportunity to use alternative, approved and effective methods in existing state leak detection and repair (LDAR) programs for wells.

The Pennsylvania Department of Environmental Protection (PADEP), has implemented an effective means of addressing fugitive VOC and methane emissions from oil and gas production operations. Through the use of Exemption 38, PADEP has required operators of new “unconventional” gas wells to institute a fugitive VOC and methane monitoring program. The program includes requirements for initial (60 days from beginning production) and annual LDAR surveys using either OGI (i.e., forward looking infrared or FLIR) methods or alternative methods including EPA Method 21 and associated reporting. The program requires prompt repairs to leaking components with a 500 ppm repair criteria.

Response: The rule as finalized includes Method 21 as well as OGI as acceptable means of conducting fugitive emissions monitoring surveys. We have also included language in the final rule that allows for the approval of emerging technologies for reducing fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Concerning existing programs, see response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Matthew H. Mead, Governor
Commenter Affiliation: State of Wyoming
Document Control Number: EPA-HQ-OAR-2010-0505-6711
Comment Excerpt Number: 2

Comment: The EPA is proposing to change "methane leak monitoring" for oil and gas production facilities. This important regulatory function reduces environmental risk and increases revenue. However, compared to Wyoming's requirements, EPA's proposal will not result in less leaks and increases the regulatory burden and expense to industry.

The EPA has essentially proposed a performance-based protocol for leak detection and repair - less leaks, less monitoring. Leak rates change because of weather, temperature, age of equipment, and other factors. Wyoming regulators require operators to check quarterly for leaks. When leaks are detected, they are repaired. Wyoming rules provide both protection and consistency. Wyoming's regulations are easy to implement, easy to follow and ensure timely leak repair. I ask the EPA to review the Wyoming Department of Environmental Quality's comments where they outline this process in detail.

The industry is to be commended for its efforts to reduce leaks. Since 2005, natural gas production has increased 43% and oil production 68%. During the same time, methane emissions from the industry have been reduced by 79%. Technologies and practices have evolved to the benefit of the environment. Wyoming's system and success make it evident that EPA's proposal is not necessary for a state with an effective system already in place.

I request the EPA defer to Wyoming.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. Concerning existing programs, see response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 6

Comment: EPA is soliciting comment on "how to determine whether existing state requirements (i.e., monitoring, record keeping, and reporting) would demonstrate compliance with this federal rule" (see 80 FR 56595). Issue: Anadarko agrees that EPA must provide an exemption for sources subject to state LDAR programs with similar program elements to the proposed Subpart OOOOa LDAR requirements. An adequate state or permit requirement should be appropriate in place of Subpart OOOOa. We believe that this allowance should be provided to existing and future comparable state LDAR programs. In the preamble of the Proposed Rule, EPA seems to agree with that proposition.

There are strong reasons to allow state requirements to operate in place of EPA proposed Subpart OOOOa, including: Congress established the Clean Air Act ("CAA") to allow states to take the lead on air programs. For example, 42 U.S.C. section 7401(a)(3) states clearly "that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States .... "; EPA's role is "to provide technical and financial assistance to State and local governments in connection with the development and execution of their [the states'] air pollution prevention and control programs." 42 U.S.C. section 7401(b)(3); EPA has approved such evaluations and decisions for other NSPS regulations (i.e., numerical limits for storage vessels, testing and vapor capture requirements for tanker trucks); State programs can allow for continued innovation in monitoring and measurement technologies, where Subpart OOOOa is limiting the technology (for example, Optical Gas Imaging ("OGI") for leak detection); States conduct a cost benefit analysis in rulemakings, which often results in the optimal strategies to achieve emission reductions to address local air quality issues; without an exemption pursuant to Subpart OOOOa for legally and practically enforceable requirements, facilities with an enforceable state requirement would also have to meet the federal requirements with no additional environmental benefit; complying with multiple programs would cause significant regulatory burden, increase compliance costs and create unnecessary confusion, with no additional environmental benefit.

State regulations with enforceable leak detection program elements can meet the obligations under Subpart OOOOa, including: method of detection, monitoring frequency, repair and verification, recordkeeping and reporting, and company program oversight. Solution: Anadarko strongly recommends that any final rule contains clear language that permits, recognizes, and allows for the development of state programs. A state program should be deemed compliant with Subpart OOOOa, if the state commits to develop a program or implement an existing program, either of which includes: a method of detection; a monitoring frequency; repair and verification; recordkeeping and reporting; and company program oversight.

This can be achieved by inclusion of an exemption in Subpart OOOOa for facilities with legally and practically enforceable federal, state, local, or tribal authority requirements to implement an LDAR program in a permit or regulation. This should be available for facilities that are located in a state that has promulgated a state program or potentially at such time in the future promulgates a state program. This should also be available for facilities that have an applicable permit condition. By allowing this exemption, EPA would still accomplish its goal of maximizing air emission reductions, while providing states the ability to implement their own effective programs and providing industry with regulatory efficiency and certainty.

Proposed revisions: The following is proposed regulatory text to address the concerns raised above (proposed edits are underlined):

§60.5365a(i) Except as provided in § 60.5365a(i)(1) through (i)(2), the collection of fugitive emissions components at a well site, as defined in§ 60.5430a, is an affected facility.

Well sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other requirement established under a Federal, State, local or tribal authority are not an affected facility under this subpart.

§60.5365a(j) The collection of fugitive emissions components at a compressor station, as defined in §60.5430a, is an affected facility. Compressor stations with a legally and practically enforceable leak detection and repair requirement in an operating permit or other requirement established under a Federal, State, local or tribal authority are not an affected facility under this subpart.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 13

Comment: Furthermore, the vast majority of oil and gas sites in the state of Texas are authorized under permits by rule (PBRs) or standard permits (SPs) and many of these authorizations already contain fugitive monitoring requirements as a condition of the permit. TCEQ believes that requiring sites to follow the proposed LDAR program when there is already an existing and comparable detection program in place at the site would only result in increased costs and complexity of overlapping fugitive monitoring requirements without any net benefit in emissions reduction. Therefore, TCEQ recommends that the EPA allow oil and gas sites to opt out of the fugitive monitoring requirements if there is a comparable LDAR program in place that has been established through a permit authorization.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 12

Comment: Duplicate Regulations: Part of Apache's existing operating procedures includes the timely repair of major leaks within our facilities. These repair procedures are also required per existing, federally enforceable state permits (e.g., Title V, Texas Standard Permit); thereby, making a monitoring program to ensure leak repair at these facilities redundant and unnecessary.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 2

Comment: The Division supports EPA's efforts to reduce leaky components at well sites and compressor stations. The Division supports EPA's efforts to reduce the inspection, monitoring, recordkeeping, and reporting burdens of overlapping federal and state oil and gas requirements. EPA designed the proposed NSPS OOOOa to complement, not complicate, existing state requirements, and solicited comment on how to determine whether existing state requirements would demonstrate compliance with NSPS OOOOa. Colorado's regulations were supported by significant members of the oil and gas industry, environmental community, and local governments. The Division believes that Colorado's robust, cost-effective leak detection and repair ("LDAR") program for components at well production facilities and natural gas compressor stations achieves similar or greater emission reductions than the proposed NSPS OOOOa LDAR. Therefore, the Division requests that EPA define Colorado's LDAR program as an alternative method of compliance with the NSPS OOOOa LDAR programs.

Section 111 of the Clean Air Act requires EPA to base a standard of performance on controls that constitute the best system of emission reduction ("BSER"), taking into account whether the cost of a control is reasonable. EPA has stated that the "best" system of emission reduction achieves the appropriate level of reductions, is of reasonable cast, and encourages technological development important to achieving further emission reductions. Generally, EPA does not prescribe a particular technological system to comply with a standard of performance, but allows a source to select any measure(s) that will achieve the emissions level of the standard. For fugitive emissions at well sites and compressor stations, EPA has identified optical gas imaging (OGI) technology with semiannual survey monitoring as the BSER for detecting fugitive emissions. The Division believes that Colorado's LDAR program meets EPA's BSER for fugitive emissions at well sites and compressor stations.

Concerning monitoring frequency and emission reductions, EPA has determined that semiannual surveys are cost-effective. In comparison, Colorado determined that a tiered inspection frequency based on facility emissions is cost-effective. Colorado's program may require fewer inspections at smaller emitting facilities than the NSPS OOOOa LDAR program but, importantly, requires more frequent inspections at greater emitting facilities. In addition to obtaining greater reductions at larger emitting facilities, Colorado determined that the tiered inspection frequency addressed potential resource and economic impacts for small businesses. Therefore, as a whole, the Division believes that the inspection frequency of Colorado's program obtains similar or greater emission reductions than the proposed NSPS OOOOa LDAR.

Concerning the monitoring technology, EPA has determined that OGI is more cost-effective than EPA Method 21, not that EPA Method 21 is less effective at identifying leaks. In fact, EPA stated that EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI, in contrast to a concentration of 500 ppm with EPA Method 21. In comparison, and as detailed in Colorado's Air Quality Control Commission, Economic Impact Analyses for Proposed Revisions to Regulation Number 7 (5 CCR 1001-9) (January 30, 2014) (see tables below), Colorado determined that inspection with either infra-red ("IR") camera or EPA Method 21 was cost-effective, and effective at detecting component leaks requiring repair.

Colorado's regulations go beyond current and proposed EPA regulations in a number of other areas. Colorado's LDAR program applies to both new and existing well production facilities and natural gas compressor stations, whereas NSPS OOOOa applies only to new and modified well sites and compressor stations. Colorado's LDAR program also encourages technological development to a greater extent than the proposed NSPS OOOOa LDAR. Under Colorado's LDAR program, the Division may approve alternative monitoring methods that meet certain quantitative or qualitative standards. Colorado's LDAR program also requires well production facilities to conduct additional audio, visual, olfactory ("AVO") leak detection inspections, which NSPS OOOOa does not require. Therefore, the Division believes that Colorado's LDAR program meets or exceeds EPA's BSER determination for fugitive emissions.

[The commenter included 2 tables showing compressor station and well production methane and VOC cost effectiveness using IR camera/Method 21 for each of their tiers]

The Division suggests EPA use the following criteria to formally support the determination that compliance with Colorado's LDAR program would demonstrate compliance with the proposed NSPS OOOOa LDAR program. First, EPA could consider the extent to which the state LDAR program applies to the same facilities as the NSPS OOOOa LDAR program: Second, EPA could consider which pollutant(s) the state LDAR program reduces in comparison to the pollutant(s) reduced under the NSPS OOOOa LDAR program. Third, EPA could consider the technologies used to inspect for leaks. Fourth, EPA could consider the leak inspection, repair, and resurvey frequencies. Lastly, EPA could consider key monitoring, recordkeeping, and reporting requirements the state LDAR program has, or should have, in comparison the NSPS OOOOa LDAR program. The Division provides a summary table below, comparing these elements in Colorado's LDAR program to the proposed NSPS OOOOa LDAR program.

	Colorado	**Proposed NSPS OOOOa**
Affected facility - wells	Well production facilities	Well sites
Affected facility - compressor stations	Natural gas compressor stations - well production facility to natural gas plant	Compressor stations - well head to custody transfer/city gate
Pollutant(s) reduced	Hydrocarbons	VOC and methane
Inspection technology	IR camera, Method 21, other Division approved	OGI

	Colorado	Proposed NSPS OOOOa
	technology/method	
Inspection frequency	Tiered - based on site emissions	Semi-annual
Repair schedule	5 days	15 days
Resurvey technology	IR camera, Method 21, other Division approved technology/method	OGI or Method 21
Resurvey frequency	15 days	15 days
Key records	2 years - date and site information, leaks, method, repair date, resurvey date	5 years - monitoring plan, date and site, repair date, resurvey technology
Key reports	Annual - total: facilities inspected, number of inspections, leaks identified and repaired	Annual - date and site information, date of repair, resurvey technology

EPA has acknowledged state regulation of well completions and LDAR at well sites in the NSPS OOOOa 2015 Technical Support Document ("TSD"). In the TSD, EPA estimated the average number of new oil wells that would be affected facilities under NSPS OOOOa, by subtracting the number of completions/recompletions already subject to regulation (i.e., Colorado and Wyoming) in order to ensure that emission reduction benefits were not calculated for sources already being controlled. Similarly, in determining the nationwide emissions from well sites, EPA subtracted the number of oil and gas wells covered by state leak regulations (i.e., Colorado, Ohio, Wyoming, Utah). As explained in the TSD, EPA excluded these sources because EPA determined that sources subject to these state regulations would not be subject to the NSPS. Therefore, the Division suggests EPA craft NSPS OOOOa such that a source can comply with these state regulations as an alternative to NSPS OOOOa LDAR. In addition, the Division suggests that EPA similarly craft NSPS OOOOa such that a compressor station can comply with state leak regulations as an alternative to NSPS OOOOa LDAR.

EPA has previously allowed a source to use a state or local regulation to determine the source is not subject to a federal regulation. NSPS OOOO and the proposed NSPS OOOOa allow a storage vessel to take into account "requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority" when determining the storage vessel's potential for VOC emissions, and thus whether the storage vessel is subject to the NSPS. EPA could use similar terms (e.g., "legally and practically enforceable leak detection and repair requirement established under a state authority") to determine whether a well site or compressor station would be subject to NSPS OOOOa LDAR.

Colorado has been at the forefront of well site and compressor station leak emission reductions, as well as other oil and gas emission strategies. EPA cited and utilized Colorado's oil and gas regulations in developing NSPS OOOOa. Colorado's state and local governments, industry, and environmental organizations expended significant resources to develop, and now implement, Colorado's oil and gas regulations. The Division believes that requiring its oil and gas industry to comply with the proposed NSPS OOOOa LDAR program in addition to Colorado's LDAR program could result in considerable administrative effort for little, if any, demonstrated additional environmental benefit. Therefore, the Division encourages EPA to craft NSPS OOOOa such that the federal rule recognizes state expertise and rules, and avoids unduly burdensome, confusing, or redundant requirements at the federal level.

Response: The rule as finalized includes Method 21 as well as OGI as acceptable means of conducting fugitive emissions monitoring surveys. We have also included language in the final rule that allows for the approval of emerging technologies for reducing fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

We do not agree with the commenter’s characterization of the storage vessel provisions. In part, the rule defines a storage vessel affected facility in terms of its VOC potential to emit. It naturally follows that if a storage vessel is subject to a legally and practically enforceable permit limit or other requirement that places a limit on the potential to emit, the limit should be taken into account when determining the potential to emit for the purpose of affected facility determination. This has nothing to do with equivalency between state and federal rules. Section 60.5397a is a work practice standard based on a multifaceted monitoring program, not an emissions limit, so equivalency is a more complicated matter. Therefore, we cannot make blanket statements that just because a facility is subject to another set of fugitive emissions monitoring standards, that source does not have to comply with §60.5397a of the final rule. In recognition of this complexity, we have added §60.5398a in the final rule to provide a mechanism to apply to the Administrator for a determination on equivalency. See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37, and section VI.K of the preamble to the final rule for more detail regarding this issue.

Commenter Name: Andrew Casper
Commenter Affiliation: Colorado Oil & Gas Association (COGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6889
Comment Excerpt Number: 10

Comment: In the alternative, EPA should at the least make clear that compliance with the Regulation No. 7 LDAR provisions is sufficient to demonstrate compliance with Quad Oa LDAR requirements, such that compliance with Quad Oa LDAR requirements is not also required (*i.e.*, is exempt from Quad Oa requirements). Such an alternative should include allowances to rely on Colorado’s LDAR program in lieu of Quad Oa’s leak detection requirements, given that Regulation No. 7 provides for equivalent work practice standards to reduce leak emissions. Colorado’s LDAR program will achieve the same or greater emissions benefits in a cost-effective manner, thus meeting or exceeding federal "best system of emissions reduction" requirements.

Specifically, Colorado's LDAR program covers both new and existing upstream O&G facilities and compressor stations. It requires monitoring at numerous frequencies determined to be cost-effective for Colorado. With respect to monitoring frequency, COGA believes it is critical that the EPA program allow each state to make its own cost-effectiveness determinations. A one-sized-fits-all approach towards mandating LDAR frequency is not the best approach. For example, whether an LDAR program is cost-effective depends on numerous factors including facility type, facility size, facility location, ease of travel, availability of gathering infrastructure, company size, and burden associated with developing and implementing databases, number, and availability of vendors, and production decline in any given location, among others. Moreover, the Quad Oa proposal does not tier frequency or otherwise tailor the program based on emissions or some other metric—rather, it would apply equally to all new and modified facilities as defined in the rule. COGA believes: (1) that the Colorado program is more stringent, overall, in its tiered monitoring frequency approach; and (2) that the one-size-fits-all EPA proposal will be inefficient and ineffective.

Colorado's program also requires OGI (labeled AIMM) monitoring along with Method 21. The Colorado program requires timely repairs of identified leaks, and specifically calls out that a leak does not constitute a violation of the rules. COGA strongly urges EPA to provide a similar provision in Quad Oa as it is critical to the effectiveness of any LDAR program to incentivize and not punish finding and fixing leaks. Finally, the Colorado LDAR program requires recordkeeping and reporting. For these reasons, Colorado's existing LDAR program already demonstrates compliance with the federal rule as proposed and we urge EPA to make this clear in the final rule. It is of utmost importance to the success of both EPA's program and Colorado's program that EPA avoid requiring that operators develop a hybrid program based on the most stringent requirement between NSPS and state program requirements, which adds an additional and unnecessary level of complexity to implementation and compliance.

While COGA requests EPA recognize compliance with the Regulation No. 7 Program as sufficient for compliance with Quad Oa (and therefore exempt from the same), COGA offers the following feedback to EPA in development of any final Quad Oa rule at the national level, given its unique experience. Colorado operators' unique experience and perspective on LDAR compliance has demonstrated that what works for some facilities does not work for all facilities. Nonetheless, the lessons learned by Colorado operators are instructive and, as summarized below, demonstrate a critical point that must be recognized in any effective LDAR program: flexibility with respect to monitoring programs and technology is paramount to LDAR compliance in Colorado and beyond. Please see Attachment 1 which describes these lessons learned as applied to specific fugitive leaks and emissions issues.

[Attachment 1 includes a "Detailed Table Presenting Colorado Lesson's Learned"]

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 2.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 4

Comment: Due to the numerous contradictions and inconsistencies between existing state regulations and the proposed NSPS LDAR regulations, we encourage U.S. EPA to incorporate language that exempts operators from any NSPS LDAR requirements where covered by an existing state program. Compliance with a state program should be considered compliance with the federal program and no further action required. MSC members now have over two years of experience in meeting the Pennsylvania Department of Environmental Protection's Bureau of Air Quality (PADEP) Leak Detection and Repair (LDAR) requirements found in Exemption Category #38 and GP-5 with great success. PADEP's requirements are focused on reducing emissions and minimizing unnecessary recordkeeping. Not included in their program is the individual component identification and tagging, detailed procedures, third party audits, submission of components, etc. MSC believes the PADEP programs are a superior method for emission reduction and should be considered sufficient for compliance with whatever is promulgated in the final rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 6

Comment: EPA Must Accept State Fugitive Emission Control Programs that are as Stringent or More Stringent than EPA's NSPS OOOOa as Alternative Methods of Compliance

EPA's NSPS OOOOa proposal solicits comments on criteria that can be used to determine whether and under what conditions well sites operating under alternative fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions. 80 Fed.Reg. at 56596; 56638. Although EPA's proposal is focused on corporate alternatives, QEP implores EPA to consider state fugitive emission control programs that are as or more stringent than NSPS OOOOa as alternative methods of compliance for NSPS OOOOa. State requirements are enforceable.

And QEP is confident that facilities subject to state fugitive emission control requirements, in states such as Wyoming and Colorado, will continue to achieve equal or better emission reduction than EPA's proposed NSPS OOOOa standards. See Colorado Air Quality Control Commission, Regulation No. 7 (revised April14, 2014). See also, Wyoming Department of Environmental Quality, Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (September 2013) and Wyoming Air Quality Standards and Regulations, Chapter 8, Section 6, Section 13 (Nonattainment new source review permit requirements) (effective June 30, 2015). Furthermore, EPA goes on to acknowledge in the preamble that "duplicative recordkeeping and reporting requirements may exist between the NSPS ... and other state and local rules" and that EPA is "trying to minimize overlapping requirements for operators." Id. at 56616. QEP appreciates EPA's concern for burdensome reporting and record keeping. EPA can significantly decrease potential burdens by allowing state and local fugitive emission control programs that are as or more stringent than NSPS OOOOa to act as alternative methods of compliance for EPA's fugitive emission control federal standard.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 19

Comment: PAW also urges EPA to allow compliance with state LDAR requirements, due to existing air permits, state regulations or voluntary commitments, to satisfy federal rule requirements and minimize regulatory burden on those operators. Wyoming has enforceable equivalent leak detection requirements in their oil and gas permitting program for certain sites, and sites subject to equivalent state LDAR requirements should be exempt from subpart OOOOa requirements. Operators with sites subject to duplicative LDAR requirements will be unnecessarily forced into creating hybrid compliance programs that will incorporate the most stringent requirements of multiple programs. This is unnecessarily burdensome and duplicative with no net environmental benefit. PAW believes the Wyoming Department of Environmental Quality is in the best position to regulate LDAR where applicable for air quality permits as they have the personnel, budget, and expertise necessary to efficiently and effectively implement and manage compliance with its program. PAW again recommends if a state is already requiring some form of LDAR, that state program should take precedent over satisfy the requirements of the Proposed Rule.

EPA solicits comment on "how to determine whether existing state requirements (i.e., monitoring, recordkeeping, and reporting) would demonstrate compliance with this federal rule." See 80 Fed. Reg. at 56,595. Any fugitive emission monitoring program required by rule, whether or not approved as part of a State Implementation Plan ("SIP"), that is legally and practically enforceable by a state or local administrative authority should be deemed adequate to satisfy any potential obligations under the Proposed Rule.

Currently in Wyoming new or modified facilities are required to incorporate fugitive emission monitoring programs if the facility is within geographic areas designated by the state. These facilities are required to submit a Leak Detection and Repair (LDAR) protocol if the facility emissions are greater than or equal to 4 tons per year of VOCs. The frequency requirement is no less than quarterly, and may consist of Method 21, infrared camera, audio-visual-olfactory (AVO) inspections or some combination thereof with at least one or more surveys employing

OGI or method 21. The monitoring plan must be submitted by operators and must be approved by the state. A plan consisting of only AVO inspections will not be accepted by the state.

Records include date and site of inspection; a list of components screened and associated dates; list of currently leaking components; list of repaired components along with the repair method and associated repair dates; and a list of successful repairs, repair delays and post-repair screenings and associated dates. All records are kept for a minimum of 3 years.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 22

Comment: EPA Should Provide an Exclusion from LDAR Monitoring for Facilities that Are Subject to State-Based Fugitive Emissions Monitoring

GPA agrees with EPA that state-based fugitive emissions monitoring systems can serve as effective substitutes for EPA's proposed LDAR program and that it would be redundant for operators to comply with both state and federal requirements under such circumstances. In cases where states already have effective fugitive emissions monitoring programs in place, applying an additional federal program would add only significant burdens without any real benefits. Such a federal plan would likely provide insignificant incremental benefits beyond what would already be achieved by the state plan while adding all of the compliance costs of a second regulatory program. In addition, EPA did not consider facilities already subject to a state-based fugitive emissions monitoring program in their cost-effectiveness analysis. However, EPA does not exclude these facilities already subject to a state fugitive emissions program from compliance with NSPS OOOOa. Including facilities already subject to a state-based fugitive emissions monitoring program in EPA's cost-effectiveness evaluation would reduce the cost-effectiveness of the rule, because facilities would incur the same costs to comply with Subpart OOOOa as a facility with no existing LDAR program, but would produce minimal to no benefits because the existing state LDAR program already reduces fugitive emissions. Thus, to the fullest extent possible, EPA should incorporate state fugitive emissions monitoring programs into the NSPS program whenever it is appropriate to so do.

Further, incorporating existing state fugitive emissions monitoring programs is consistent with the purpose of the CAA. Congress established the CAA to allow states to take the lead in developing programs to address air pollution. For example, 42 U.S.C. § 7401(a)(3) states "that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States…." In contrast, Congress intended that EPA's primary role would be "to provide technical and financial assistance to State and local governments in connection with the development and execution of their [the states'] air pollution prevention and control programs." 42 U.S.C. § 7401(b)(3). Incorporating state fugitive emissions monitoring programs would thus be consistent with the purpose of the CAA. Moreover, such an approach can promote continued innovation in monitoring and measurement technology for fugitive monitoring equipment while also allowing states to tailor their programs to address local air quality issues.

In recognition of the potential benefits of utilizing existing state programs, EPA requests comment on:

criteria we can use to determine whether and under what conditions all new or modified well sites or compressor stations operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites or compressor stations fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining.

80 Fed. Reg. at 56,614. GPA believes it is appropriate for EPA to rely on state-based fugitive emissions programs that are at least as stringent as EPA's proposed regulations. This is consistent with federal environmental programs that are administered by the states. See, e.g., 40 C.F.R. § 123.25(a) (Clean Water Act); 40 C.F.R. § 145.11(b)(1) (Safe Drinking Water Act Underground Injection Control Program); 40 C.F.R. § 270.10(i) (Resource Conservation and Recovery Act). It is also consistent with EPA's past practice in the NSPS program. See 40 C.F.R. § 60.103a(g) (approving Bay Area Air Quality Management District ("BAAQMD") regulations as an alternative compliance option for work practices for flares); 40 C.F.R. § 60.107a(h) (approving BAAQMD and South Coast Air Quality Management District ("SCAQMD") regulations as an alternative compliance option for flares). It is also consistent with EPA's past actions under the NSPS program.

Thus, GPA urges EPA to include in the Code of Federal Regulations a list of state monitoring programs that qualify as alternative methods of compliance based on a comparison of the definition of fugitive components, monitoring frequency, scope, repair time and delay of repair, and enforcement and audit authority. GPA's members have significant experience operating in states with existing fugitive emissions programs and we look forward to working with EPA to develop a process and standard to recognize such program as alternative compliance options under the NSPS program.

To clarify that such programs serve as an effective substitute for EPA's proposed regulations, GPA urges EPA to modify the definition of a compressor station affected facility in 40 C.F.R. § 63.5365a(j) as follows:

The collection of fugitive emissions components at a compressor station, as defined in §60.5430a, is an affected facility. ***<u>Compressor stations with a legally and practically enforceable leak detection and repair requirement established under a Federal, State, local or tribal authority are not affected by this subpart</u>***. *For purposes of § 60.5397a, a "modification" to a compressor station occurs when...*

This revision will ensure that sources already subject to requirement that are at least as stringent as EPA's fugitive emissions monitoring program will not be forced to comply with two redundant standards. GPA asserts that any state program should be considered equivalent if the state commits to develop an equivalent program with work practice elements, such as, a method of detection, a monitoring frequency, repair and verification, and recordkeeping and reporting.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Dan G. LeRoy
Commenter Affiliation: Legacy Reserves Operating LP
Document Control Number: EPA-HQ-OAR-2010-0505-6882
Comment Excerpt Number: 13a

Comment: The proposed rules are unnecessary and duplicative of existing state and federal requirements, as well as voluntary industry practices.

Emissions are already adequately addressed through state law regimes in most of the major oil and gas producing states. For example, Colorado, Wyoming, Ohio, Pennsylvania, and Texas all have state regulatory requirements designed to limit natural gas emissions from oil and gas operations. These state rules share many of the same goals as the Methane NSPS, but their requirements differ in ways that may make it hard or impossible for operators in those states to comply with both sets of rules. For example, in Colorado the frequency of inspections for well production facilities and compressor stations differ based on their actual uncontrolled VOC emissions, while the Methane NSPS focuses on the percent of leaking components. Colorado also requires audio, visual, and olfactory inspections, while the Methane NSPS mandates that operators use OGI technology for inspections.

These state regimes are continuing to evolve and find creative solutions best designed to address the unique circumstances in their region. Because each geologic formation and shale play is unique, oil and gas operating practices can look very different across varying regions of the country. There is no one-size-fits-all solution. Legacy believes that EPA's Methane NSPS is unnecessary and should be withdrawn because state regulators are better equipped to address the particular issues in their states. However, if EPA does move forward with this proposal, it should at the very least consult with its state counterparts first to learn from their experiences regulating in this area, and determine if portions of the Methane NSPS are unnecessary, duplicative, or conflict with existing state rules.

This need to coordinate with the states is amplified by the fact that the Methane NSPS intrudes into an area historically regulated by the states and creates duplicative and conflicting regulatory obligations without a commensurate environmental benefit. The Clean Air Act repeatedly recognizes the value of state and federal cooperation and the important role that states play in implementing the Act. Unlike many other air regulations, the Methane NSPS leaves no room for states to exercise regulatory authority over the sources within their borders. Instead, EPA has usurped the state's traditional rule by directly regulating these sites. EPA should be mindful of these concerns, and either withdraw the Methane NSPS or craft a final rule that respects the expertise and traditional role of states in regulating these issues.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37, for information on using a state program in lieu of the requirements in the final rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 104

Comment: EPA Did Not Consider The Inconsistencies With State LDAR Programs (CO, PA, WY, TX, OH, Etc.). This Creates Duplicative And Potentially Conflicting Requirements With Little Environmental Benefit

Similar to the exemption for storage vessels under NSPS Subpart OOOO, §60.5365(e)(3), well sites or compressor stations subject to legally and practically enforceable requirements in an operating permit or other requirement established under Federal, state, local or tribal authority should be exempt from Subpart OOOOa LDAR requirements.

For example, the non-rule standard permit for oil and natural gas facilities in Texas requires quarterly monitoring using M21 or optical imaging of valves and quarterly monitoring of pumps, compressor seals, and agitator seals without shaft sealing systems if the site fugitive emissions exceed 10 tons VOC/year.

However, proposed Subpart OOOOa requires OGI at least semiannually (and less frequently depending on percentage of leakers) for all components. Managing multiple LDAR programs for state and federal rules will create unnecessary compliance complexities for facilities trying to comply with the varying rules. Therefore, Subpart OOOOa should have allowances to rely on state LDAR programs in lieu of those in Subpart OOOOa if the state rules provide for equivalent work practices to reduce leak emissions.

The suggested exemption provided in the rule text edits at the end of this section (see Section 27.2.12) is consistent with the approach EPA used to quantify the cost effectiveness and the overall net benefits in the benefit-cost analysis for fugitives. Specifically, EPA excluded well sites in regulated states in their baseline and projections of affected oil and natural gas well sites in 2020 and 2025. The exclusion of well sites in regulated states has the effect of reducing both costs and emission reductions, so there is no net effect on cost effectiveness. However, the rule as proposed does not exclude well sites in regulated states from complying with OOOOa, which is not consistent with EPA's cost analysis. If well sites in regulated states are not exempt from Subpart OOOOa requirements, those affected well sites would incur higher costs to implement the additional LDAR requirements with little to no net emissions reductions. The resulting cost effectiveness would be higher than EPA estimated if those regulated well sites are not exempt. Therefore, EPA should exempt well sites subject to state LDAR requirements to be consistent with the approach used to estimate cost effectiveness. This will also prevent operators from having to develop a hybrid program based on the most stringent requirement between NSPS and state program requirements, which adds additional complexity to compliance.

In the Preamble, EPA requested comment on how to determine whether existing state requirements would demonstrate compliance with this federal rule. The table provided in Attachment F compares existing state LDAR requirements for Colorado, Pennsylvania, Wyoming, and Ohio to the proposed OOOOa requirements. Highlighted cells indicate where the proposed OOOOa requirements are more stringent than the state level requirements. API believes that any program (state, local, or even voluntary) that has the same conceptual elements (i.e. work practice standards for monitoring, recordkeeping and reporting) should be considered equivalent to OOOOa and therefore exempt from OOOOa LDAR requirements.

Response: The EPA thanks the commenter for the information. We disagree that we did not consider state programs during the rulemaking process. We acknowledge that several states have implemented leak detection and repair programs for compressor stations which we reviewed and evaluated during our analyses for the final rule. See discussion in the State LDAR comparison Memo in the Oil and Natural Gas docket.

See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. Concerning existing programs, see response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Shawn Bennett, Executive Vice President
Commenter Affiliation: Ohio Oil & Gas Association (OOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6921
Comment Excerpt Number: 9

Comment: Similarly, EPA should provide an exemption to the proposed LDAR requirements for those facilities that have a federally enforceable state permit authorization similar to the Ohio GP-12 which has federally enforceable LDAR requirements. Such an exemption would eliminate all unnecessary inconsistencies by recognizing that some state programs have already implemented sufficient requirements through their permit programs.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 7

Comment: Item- Exemption for Facilities Subject to State Regulatory Driven Fugitive Emissions Control Requirements

Several states (e.g. Colorado, Pennsylvania, Ohio, and Wyoming) have either promulgated regulations or implemented air permit requirements intended to control fugitive emissions via implementation of a Leak Detection and Repair program. In cases where states have implemented effective fugitive emissions control programs, promulgation of a federal program would not only be duplicative but could also be in conflict with state regulatory requirements.

Recommendations:

SWN recommends that the final rule exempts or excludes well sites and compressor station sites subject to a state regulatory or permit driven program from the federal requirements. This could be achieved by inclusion of the following:

60.5365a(i)(3) A well site that is subject to controlling fugitive emissions under state regulatory driven requirements is not an affected facility under this subpart.

60.5365a(j)(3) A compressor station site that that is subject to controlling fugitive emissions under a state regulatory driven requirements is not an affected facility under this subpart.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 6

Comment: Alignment with States: Several jurisdictions, including Colorado, Pennsylvania, Ohio, Wyoming and California Air Districts have existing leak detection and repair programs. This rule does not provide a clear mechanism for alignment with these existing programs. In some areas, such as the San Joaquin Valley, a company could be required to conduct a Method 21 inspection under local requirements, and an entirely separate OGI inspection of the same facilities under Subpart OOOOa/the control technique guidelines (CTGs). In Colorado and Pennsylvania, the methods and frequencies are more flexible, but still do not align with the proposed federal program and will require some duplicative inspection work and significant additional recordkeeping for no additional benefit. One option for alignment would be to make all operations that are covered by a state program not affected sources, similar to the tank provisions in Subpart OOOO. Another option would be to allow state programs to qualify as an alternative compliance mechanism.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 10

Comment: Antero urges USEPA to exempt well sites from federal LDAR requirements if they are already subject to an enforceable state program.

Several states are working with the regulated community on the effects of LDAR and inspection programs. Those efforts are showing that there can be thousands of components at a facility while a relatively small percentage leak, so imposition of the proposed Part OOOOa LDAR requirements is not necessarily a cost-effective way to gain significant emission reductions. For that reason, USEPA should allow the issue to be driven by state programs and exempt sites that are subject to an enforceable state LDAR program. Absent such exemptions, operators would be forced to comply with duplicative and sometimes inconsistent monitoring, reporting and recordkeeping.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Comment submitted by Todd Parfitt, Director
Commenter Affiliation: Wyoming Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2010-0505-6993
Comment Excerpt Number: 9

Comment: Deferring to existing state fugitive emissions monitoring plans

The EPA's proposed amendments to NSPS OOOO, when in conflict with existing state FM plans or when the rule creates duplicative FM requirements, must give deference to an existing state FM plan and allow the affected source to follow state FM requirements in lieu of NSPS OOOO requirements. AQD has incorporated FM plans into oil and gas permits for over six years and as a result has implemented FM plans for thousands of existing oil and gas well sites. If the EPA does not defer to existing state FM plans, then the administrative burden to revise existing plans to be consistent with new NSPS OOOO requirements after a modification occurs will be considerable. Additionally, the administrative effort to comply with existing state FM plans for existing well sites and comply with different FM requirements for well sites subject to NSPS OOOO will be significant.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 9

Comment: State primacy should preempt federal regulations. State primacy for LDAR requirements in the rule is one of Pioneer's primary concerns and urgent requests regarding this proposed rule. The CAA is structured such that states should have primacy and be primarily responsible for compliance with the requirements of the Act. Many of the states with the most active shale plays, such as Colorado where Pioneer has upstream operations, have implemented state regulations to address many of the emissions sources targeted in the proposed Subpart OOOOa regulations. Under the premise of cooperative federalism, EPA should defer to existing state regulations and deem compliance with state regulations on the same sources as constituting compliance with the final Subpart OOOOa regulations. Just as EPA has done with the storage tank source category in the 2012 NSPS allowing tanks that are permitted under a state or federally enforceable permit to be exempt from Subpart OOOO, EPA should allow facilities in states that have a state or federally enforceable LDAR program in place to be excluded from those requirements in this rule as well. State primacy should apply to operations in states that have a comprehensive program for oil and gas operations such as Colorado, as well as for sites that are under a specific state enforceable permit to conduct LDAR monitoring (such as the Barnett Shale (i.e. non-rule) Standard Permit in Texas). Suggested language using Colorado's enforceable state LDAR program as an example is as follows, "Well sites and natural gas compressor stations located in Colorado that would be an affected facility subject to the requirements of this section and subject to the requirements of an enforceable state LDAR program may elect to comply with the state LDAR program as an alternative to complying with this section. The owner or operator of an affected facility must notify the Administrator that the affected facility is in compliance with Colorado Regulation 7 as codified in statute."

As IPAA/AXPC emphasizes, duplicity and inconsistency between state and federal regulations simply adds to the cost of compliance with little to no additional benefit to the environment. The mischief of having to comply with two different programs would be highly problematic for operators requiring extensive time and additional manpower for the monitoring, but also for the recordkeeping and reporting aspect. Pioneer believes that forcing operators in Colorado to comply with duplicative and arguably less stringent federal rules would undermine the CAA's cooperative federalism, and waste the immense efforts and costs local operators and the State of Colorado have just spent implementing Colorado Regulation 7. EPA's proposed regulations essentially punish states and operators within those states that proactively moved to address fugitive admissions. Such an approach does not make for sound policy.

It is extremely difficult to compare the stringency of a state LDAR program versus EPA's proposed LDAR program. Frequency of monitoring per Colorado's program, for example is based on the volume of emissions at a site, with no de minimis exemption, whereas EPA's proposal is based on an initial fixed semiannual inspection, followed by performance based adjustments. Colorado's Regulation 7 program also requires monthly auditory, visual, and olfactory (AVO) inspections and repairs to be made within 5 days of detection (however with a delay to 15 more working days with good cause shown) versus EPA's proposed 15 calendar days, and also includes extensive recordkeeping and reporting requirements. However, regardless of the comparison to arbitrarily determine stringency which would be very difficult based on various thresholds, methodologies and other differences between state programs, states with existing, legally enforceable LDAR programs should be deemed sufficient and compliance with the state program deemed as compliance with the finalized federal program.

As IPAA/AXPC argue, to the extent a party (whether EPA or a third party) believes an existing state program is inadequate, the burden should be placed on the entity making the allegation, and EPA should establish a process to address the complaint. Additionally, consistent with the CAA, the state programs should control and EPA should implement procedures in the final regulations for states to submit for approval a state-based LDAR program that is deemed sufficient to satisfy EPA's final LDAR requirements.

Response: We are aware that some states have fugitive emission programs in place. We carefully evaluated existing state and local leak detection and repair programs when developing these federal standards and attempted, where practicable, to limit potential conflicts with existing state and local requirements. Due to the differences in the sources covered and the requirements, determining equivalency through direct comparison of the various state programs with the NSPS has proven to be difficult. We also did not find that any state program as a whole would reflect what we have identified as the BSERs for all emissions sources covered by the NSPS. In any event, federal standards are necessary to ensure that emissions from the oil and natural gas industry are controlled nationwide. See State LDAR Comparison Memo in the docket for further discussion.

The Clean Air Act does not envision that less stringent state requirements be given primacy over federal requirements. To the contrary, Section 116 makes clear that a state may not "adopt or enforce any emission standard or limitation which is less stringent than [a section 111] standard." However, depending on the applicable state requirements, certain owners and operators may achieve equivalent or more emission reduction from their affected source(s) than the required reduction under the NSPS by complying with their state requirements. States may adopt and enforce standards or limitations that are more stringent than the NSPS. See CAA section 116 and the EPA's regulations at 40 CFR § 60.10(a). For states that are being proactive in addressing emissions from the oil and natural gas industry, it is important that the NSPS complement such effort. Therefore, in the preamble of the final rule, through the process described in section VI.K for equivalency determinations, owners and operators may also submit an application requesting that the EPA approve certain state requirement as "alternative means of emission limitations". The application would include a demonstration that emission reduction achieved under the state requirement(s) is at least equivalent to the emission reduction achieved under the NSPS standards for a given affected facility. Consistent with section 111(h)(3), any application will be publicly noticed, and the EPA will provide an opportunity for public hearing on the application and on intended action the EPA might take. The EPA will also publish its determination in the Federal Register.

The action that we took with respect to tanks does not present a parallel situation. In that action, the Agency concluded that tanks with potential to emit below a threshold of 6 tons per year would not be considered affected facilities. In doing so it recognized that state enforceable limits could be an appropriate mechanism for holding emissions below that threshold. Sources were not excluded from the NSPS simply because they were subject to a state program but because of what that program meant relative to the emission thresholds in that rule.

Commenter Name: Comment submitted by Todd Parfitt, Director
Commenter Affiliation: Wyoming Department of Environmental Quality
Document Control Number: EPA-HQ-OAR-2010-0505-6993
Comment Excerpt Number: 3

Comment: After reviewing the Proposed Rule, AQD is providing comment on the EPA's proposed performance standard for fugitive emissions. The proposed performance standard for reducing VOC and methane emissions from fugitive sources at well sites and compressor stations requires the implementation of fugitive emissions monitoring (FM) plans. EPA's prescriptive approach to FM is not consistent with AQD's current regulatory process for reducing emissions from sources of fugitive VOC emissions. AQD's minor New Source Review (NSR) program requires the application of best available control technology (BACT) to all permitted oil and gas sources, fugitive sources included. Oil and gas operators are required to quantify potential VOC emissions from fugitive sources and then, based upon applicable presumptive BACT (P-BACT) emissions thresholds, determine whether or not a FM plan covering all fugitive emissions from the production site is required. AQD's application of BACT for fugitive sources at well sites is based upon the potential VOC emissions associated with the onsite equipment. In accordance with AQD's *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance,* operators may calculate total hydrocarbon fugitive emissions by multiplying the number of components at a site by the average emission rates of total hydrocarbon (THC) to be assumed for all components in hydrocarbon service installed at a site. The average emissions rates were obtained from the EPA Bulletin Board (Leaks_OG.WP5; 8/9/1995). Using this method, the only information needed to quantify fugitive THC is a count or estimate of the number of flanges, connectors, open-ended lines, pumps, valves and "other" components at the site grouped by stream (i.e., type of service: gas, light oil, heavy oil, water/oil). To determine VOC emissions, operators multiply the THC emission rates by actual measured weight fractions for each stream. By determining potential fugitive VOC emissions from each well site, AQD is able to develop a consistent approach by which to approve flexible FM plans tailored to site-specific operations. The broad approach proposed by the EPA does not consider potential emissions when determining applicable FM requirements. While this approach may simplify how FM monitoring requirements are determined, it may lead to unintended results. For example, if a company is implementing enhanced oil recovery using CO2 then a producing oil well could be required to implement FM if the production rate is above 15 barrels per day, even though the potential VOC and/or methane emissions could be insignificant, based upon lab analyses of produced oil and/or produced gas samples. The EPA must consider site-specific potential VOC emissions when determining if FM is applicable to the well site and when determining appropriate FM monitoring requirements. Furthermore, if a state implements a plan to reduce fugitive emissions from well sites that is site-specific and based upon worst case emissions then the EPA should defer to the state plan.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37.

Commenter Name: : Josh W. Luig
Commenter Affiliation: Veritas Energy, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6797
Comment Excerpt Number: 47

Comment: EPA should withdraw the Methane NSPS and allow the industry to continue to address natural gas emissions through best practices.

Alternatively, EPA should exempt affected facilities in states with their own state VOC and methane emissions regulations from the requirements in the Methane NSPS.

Response: We disagree with the commenter's recommendation that LDAR monitoring be withdrawn from the final rule. See responses to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37 and DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)
Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 12

Comment: LDAR program should maintain consistency and minimize duplicity with current individual state programs

Current state LDAR programs focus on reducing fugitive emissions at a few high magnitude emission sources because data and studies indicate a large majority of total methane and VOC emissions stem from these high magnitude sources ("fat tails"). The experience gained from fat tail focused LDAR programs indicates effective management of fugitive emissions. Following the initial survey, monitoring frequencies more often than annual are unjustified and simply not necessary.

Response: We acknowledge that several states have implemented leak detection and repair programs for compressor stations which we reviewed and evaluated during our analyses for the final rule. See discussion in the State LDAR comparison Memo in the Oil and Natural Gas docket. See responses to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37, for a discussion of state program equivalency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 86

Comment: Federal laws should be stronger than state laws because states are influenced by too many special interests and don't take everybody's welfare into account. The first law should be, Do no harm.

Companies should have to monitor their emissions and should be liable for environmental degradation, just like they've been liable for toxic waste. CEOs who make a hundred million dollars a year should be asked to pay for their carbon and methane emissions. Right now they are polluting without paying for their damage, and the most vulnerable are the first to suffer.

Response: We agree that companies should have to monitor emissions. The final rule includes compliance requirements for all affected facilities. These requirements include specific monitoring, recordkeeping and reporting requirements that the regulatory agency can use to determine compliance. See response to DCN EPA-HQ-OAR-2010-0505-7058, Excerpt 37, for a discussion of state program equivalency.

Commenter Name: J. Roger Kelley
Commenter Affiliation: Domestic Energy Producer's Alliance (DEPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6793
Comment Excerpt Number: 12

Comment: Proposed NSPS OOOOa's timing for fugitive emissions requirements is problematic and unworkable for several reasons. Upon finalization of the rule, the proposed fugitive emissions requirements would immediately go into effect for onshore affected facilities that have "commence[d] construction, modification or reconstruction after September 18, 2015." This will cover numerous sources that have been constructed or modified between September 18, 2015, and the date the rule eventually goes into effect. To require immediate compliance with fugitive emissions requirements for all these sources will be unreasonably burdensome and even unworkable for many localities due to the remote nature of these facilities, and, depending on the time of year, weather difficulties in harsh and cold climates. The proposed fugitive emissions regulations require the engagement of consultants as well as procurement of equipment, and it would be impossible to coordinate both for numerous sources across a rural (and possibly winter) landscape. In addition, supply issues associated with both qualified consultants and equipment inventory could inhibit compliance with the rule. DEPA therefore requests that EPA allow for a long-term phased implementation of the Proposed NSPS OOOOa fugitive emissions requirements. DEPA anticipates that time required to adequately consider logistics, resources and to develop the processes required to have an adequate fugitive emissions monitoring program may take up to five years.

Response: Based on comments received from OGI equipment suppliers and OGI service providers, we do not agree that there will be a shortage of OGI equipment or trained contractors on the effective date of the final rule. However, we agree with commenters that owners and operators of both wells sites and compressor stations need time to complete critical steps in order to establish their program's infrastructure and build a foundation to assure continuous compliance. For these reasons, we are requiring in the final rule that the initial monitoring survey must take place within one year after the date of publication of the final rule in the Federal Register or within 60 days of the startup of production for well sites or 60 days after the startup of a new compressor, whichever is later. We believe that small businesses in particular may need this additional time to develop monitoring plans because they have less staff available for these activities. See sections VI.F.1.g and VI.F.2.f of the preamble to the final rule for more detail regarding this issue.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 15

Comment: EPA's estimate of 20,000 active wells in 2012 does not take into consideration the number of facilities that have been built in the last 4 years due to the boom cycle the industry has gone through. Many of these facilities would be subject to the rule upon modification. Therefore, we believe that EPA is drastically underestimating the number of facilities that would be impacted by the rule as well as the amount of personnel required to conduct fugitive monitoring.

Response: We disagree with the commenter that we have not considered the cyclic nature of the oil and natural gas industry. The number of wells used for calculating the impacts of the final rule were derived from the DrillingInfo database. The DrillingInfo database includes the most recent completion date for all reported wells in the US. The database in 2012 identifies wells initially fractured in 2012 and wells that were refractured (recompletions) in 2012. From this number of wells, the EPA subtracted wells that were assumed to be covered by state leak regulations as of the effective date of the revised NSPS. Based on our research, four states have recently enacted leak regulations; Colorado, Ohio, Wyoming and Utah. Projections from the National Energy Modeling System (NEMS) Oil and Gas Supply Model were used to estimate the total number of new natural gas completions, both conventional and hydraulically fractured in the years 2020 and 2025.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 15

Comment: Second, the proposed fugitive emissions regulations require the engagement of consultants as well as procurement of equipment, and it would be impossible to coordinate both for numerous sources across a rural (and possibly winter) landscape. Third, supply issues associated with both qualified consultants and equipment inventory could inhibit compliance with the Proposed NSPS OOOOa. NDPC therefore requests that EPA allow for a long-term phased implementation of the Proposed NSPS OOOOa fugitive emissions requirements. NDPC anticipates that time required to adequately consider logistics, resources and to develop the processes required to have an adequate fugitive emissions monitoring program for all assets in North Dakota will take up to five years.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 11

Comment: §60.5397a Fugitive Emissions: This section addresses fugitive methane and VOC emissions from well site components when average production is greater than 15 BOE/day during the first 30 days of production.

Rule Application: Existing regulatory protocol does not consider the geographic and logistical constraints of the oil and gas exploration and production industry. The proposed LDAR program is only suitable in a single large facility setting where all site components are in one location. In the case of Apache's current upstream operations and using a classic definition of "facility", LDAR activities would encompass 17,300 production wells and 5,400 associated production facilities located across a wide 132,000 square mile area. Using the Quad O definition of "an affected facility", the number of facilities subject to monitoring and reporting could more than triple to 16,204.

Implementation of a full LDAR program for affected wells must also consider the cost and local availability of additional service providers and whether consultants can feasibly monitor all the required components according to the proposed rule. In comparison, Apache's cost of air travel to applicable regions, car travel mileage to the wells' remote locations, and lodging costs (as monitoring staff will most likely not be local) are significant and additional to the costs associated with LDAR in a centralized facility such as a refinery. These complex logistical issues teamed with the program's intent to monitor all well site components, versus focusing on the highest potential emitting components, leads to an ineffective program that does not efficiently reduce emissions.

Response: The EPA disagrees with the commenter that focusing on the highest emitting components represents BSER for the purposes of developing a consistent national New Source Performance Standard. In order to achieve the goals of reducing fugitive emissions of methane and VOC, the EPA is finalizing semiannual monitoring and repair at well sites. Monitoring of the components must be conducted using optical gas imaging (OGI) and repairs must be made if any visible emissions are observed in accordance with the general duty provisions specified within the final rule. Method 21 may be used as an alternative to OGI at a repair threshold level at 500 parts per million (ppm). Please see section VI.F of the preamble to the final rule for more information.

Concerning travel costs for remote locations, the EPA did take such costs into consideration. See Chapter 4 of the TSD for the final rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 117

Comment: EPA Did Not Account For The Limited Availability Of Trained Personnel And Equipment To Complete Monitoring

In the Preamble, EPA indicated they were co-proposing monitoring surveys on an annual basis at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform a semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.

Many third party LDAR companies exist that perform regulatory work for LDAR in downstream portions of the petrochemical industry. However, most API companies that have implemented voluntary LDAR programs have performed their work internally with their own personnel. These companies took considerable time to train their initial core staff and required in many cases more than a year to have such a program fully operational.

Based on discussions with both OGI Instrument manufacturers and trainers, there is likely to be an initial delay in providing OGI instruments and training to meet demand once OOOOa is promulgated. EPA should provide an initial compliance period of 1 year after publication of the final rule in the Federal Register to allow LDAR detection equipment manufacturers and training organizations to meet the initial demand for equipment and training.

As well, a backlog of sites constructed between the proposal date and 60 days after the promulgation date will exist that will take time to develop any required monitoring plans in the final rule, in addition to needing time to smoothly implement a monitoring program which includes procurement of crews, equipment, and training as described above.

API requests a one-year plus 60 days phase in period from the promulgation date for compliance with the LDAR requirements, as EPA provided under §60.5370 by setting the compliance date to the later of October 15, 2012 or startup, and in defining affected facilities under §60.5360 relative to August 23, 2011. In the Response to Comments for OOOO, EPA indicated that the one-year phase-in was necessary to provide time for operators to have time to establish the need for control devices, procure and install devices. For similar reasons, a one-year phase in should be provided for the LDAR requirements to allow operators time to purchase monitoring devices, conduct training, and establish protocols.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 32

Comment: Proposed 40 C.F.R. § 60.5370a(a) requires compliance within 60 days after publication of the final rule in the Federal Register. This is not feasible, realistic, or reasonable. One of the most difficult aspects of implementing a new LDAR program is the time required to set it up. This includes tracking systems (databases), allocating or hiring personnel, and conducting training. Sixty days is not even close to sufficient time for operators to perform these tasks for hundreds, if not thousands, of facilities. In addition, as experienced in Colorado, there may not be sufficient, trained third parties available to implement these programs in certain areas. There will be numerous operators (or contractors) that will have to invest in new monitoring equipment. Lead time alone for ordering monitoring equipment, such as OGI, is, itself, approximately 60 days. When OOOOa is finalized, this will likely increase the lead time based on increased demand for such instrumentation by operators. When Colorado finalized its LDAR requirements in Regulation 7, CDPHE allowed nearly 8 months for operators to begin LDAR monitoring using Approved Instrument Monitoring Method (AIMM). As with the storage vessel requirements under the original NSPS OOOO, the Alliance recommends revisions to the rule include reasonably sufficient implementation time. The Alliance suggests 9 to 12 months as a reasonable implementation timeframe.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Anonymous public comment
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6863
Comment Excerpt Number: 1

Comment: I am writing to respond to the concern about the availability of OGI contractors as well as the effectiveness of OGI verses Method 21.

First, I would like to respond to the availability of this service and experienced operators. I am partners in a company with two operators that each have over 5000 hours operating the camera. Their experience is in a broad range of areas to include Subpart W inspections, refinery inspections, pipeline inspections using a helicopter, leak inspections on tank and well locations and reporting to name a few. We have been in touch with FLIR, the company that manufactured the camera we use, to find out the availability of more cameras should we need to purchase more to respond to the need of Oil and Gas operators. They assure us the availability is there. We understand this equipment is expensive and a lot of the operators will not be able to use their capitol to purchase the equipment, hire staff to operate it and train them. We at Morris & Mayfield Leak Detection have invested the capitol, spent the time training and, as mentioned above, have the real world experience to perform these inspections and respond to their needs.

Response: The EPA thanks the commenter for the information that was provided. We agree with the commenter on the availability of OGI instruments.

Commenter Name: Mark Boccella, Americas Business Development Manager, Optical Gas Imaging
Commenter Affiliation: FLIR Systems, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-7063
Comment Excerpt Number: 7

Comment:

VIII.G.1	Fugitive Emissions from Oil and Natural Gas Production Well Sites
Pg. 249	We are co-proposing monitoring survey on an annual basis and at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help us evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.
VIII.G.1	Fugitive Emissions from Oil and Natural Gas Production Well Sites
Pg. 260	We solicit comment on both the availability of OGI instruments and the availability of qualified OGI technicians and operators to perform surveys and repairs.

FLIR Systems is a world leader in the design, manufacture, and marketing of sensor systems that enhance perception and awareness. We are also the pioneer of Optical Gas Imaging (OGI) technology. Recently, the availability of OGI equipment and trained personnel has been brought into question; therefore we would like to take this opportunity to address this concern by offering some insight into how our operations can be scaled.

<u>Production</u>

With multiple production facilities across the United States and robust financials (2015 Revenue expectations of $1.52–1.57B), we are appropriately positioned to scale the production of OGI equipment as needed. The main reason for this is because FLIR is truly vertically integrated, as we own and operate the large majority of our supply chain. This begins with the IR detector and cryo-cooler assembly, which are the core components of an OGI camera. These are both created solely by FLIR and are also used in a wide variety of other imaging, thermography, and security products, including airborne and ground-based surveillance systems. The large majority of these products are Commercial-off-the-shelf (COTS) systems, which require us to have true scalability for spikes in growth across multiple markets.

We have thoroughly reviewed our production capacity of key components and have confirmed that even a 3X increase in demand of GF320/GF300 cameras would fit within the existing production growth plan for cooled sensor engines slated for 2016. Larger increases in demand would not require equipment or infrastructure expansion and could be scaled quickly, likely within the span of time between the finalization of an EPA rule and implementation.

We have been specifically asked by the Alberta Energy Regulator if we could build and deliver an additional 300 GF320/GF300 cameras in the next calendar year. The answer is yes, quite easily, as our current production capacity far exceeds this estimated increase in demand.

Service & Training

Additionally, we have confirmed internally that we can also appropriately scale the associated service of equipment and training of individuals via our Infrared Training Center (ITC). It is important to note that FLIR has service locations all over the world that currently work on thousands of IR cameras every month. We have confirmed internally that we can reallocate resources to handle an increase in service demand fairly easily.

With regards to training, FLIR offers Optical Gas Imaging courses both at our corporate headquarters and locally through engineers and direct employees in the field. Our Infrared Training Center has reported that it would take approximately 30 days to double the monthly amount of individuals trained on Optical Gas Imaging and 60 days to triple the number.

Rental & Leasing

Many options also exist for OGI inspections beyond the purchase of an OGI camera. For instance, a large fleet of rental cameras are available from FLIR as well as other equipment rental companies that service the industry. Additionally, the quantity of available rental cameras can triple in less than one month if the demand were present.

Service Providers & Contractors

Over the past 10 years, there have been a large number of service consultants using OGI equipment created throughout the country. This group can be rapidly expanded through existing training and equipment leasing programs. Furthermore, the declining price of oil has put a burden on many field-service companies around the country. Because of this shift, we have recently seen a transition where many of these existing companies are leveraging OGI surveys as a way to re-invent themselves in a market where they already have considerable expertise. We expect this transition to continue with the increased adoption of new inspection technologies, such as Optical Gas Imaging.

In conclusion, FLIR is well positioned to swiftly scale our OGI business to meet any new demand, thus ensuring that the necessary equipment and personnel will be available to perform monitoring and inspection programs irrespective of frequency.

Response: The EPA thanks the commenter for the information that was provided.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 24

Comment: I heard earlier this morning a question of, will there be availability of OGI technology?

As the manufacturer of FLIR the leading manufacturer of optical gas imaging worldwide, I can tell you that we are ready with operations to build the cameras required to meet the necessary goals. All of the critical components are ones that we build ourselves and can ramp up and scale that production. I've also seen where there's questions of will there be enough trained operators. Our FLIR training center offers a three-day certification class, and that's something where we can immediately scale that operation to double or triple. What we're doing right now can go beyond that for training operators very quickly and training consultants.

I'd like to go into a few of the advantages of OGI. First, it's highly effective. Since the introduction of our first OGI camera, our customers have found thousands of leaks each year and have significantly reduced their fugitive emissions. Many customers have found significant leaks that have paid for their investment quicker than expected, some within a few days of the startup of their camera.

Recently, Jonah Energy from Wyoming shared their experience in public comments to the Wyoming Department of Environmental Quality, Air Quality Division, saying, each month, Jonah Energy conducts infrared camera surveys using a FLIR camera at each of our production facility locations. Since the implementation of Jonah Energy's enhanced direct inspection and maintenance program, EDINN, in 2010, we have conducted over 16,000 inspections and repaired thousands of leaks that were identified by the FLIR camera. Based upon the market value of VOC emissions that have been eliminated, they have paid for their entire leak detection and repair program.

In Suffolk County, Wyoming, as part of the Upper Green River Basin, it's classified as a large ozone nonattainment zone. Jonah's program, including OGI, had as one of its goals to reduce

VOC emissions by 75 percent. They've exceeded that goal, and in 2012, 2013, 2014, and so far in 2014, they've had zero days above the 75 parts per billion for ozone in that area. That's a wonderful success. While achieving that goal, they have been profitable. It's actually reduced their costs and increased their profitability by operating a monthly OGI program.

OGI's efficiency is due to its unique ability to be able to visualize gas leaks and see their source. Estimates for the speed of OGI compared to Method 21 vary, but our most conservative estimate is that it's nine times faster to use an OGI camera versus traditional Method 21 instruments.

In addition, since the operator can see the source of the leak, they're in a great position to be able to make the repairs on site. At Jonah Energy, initially their goal was to make 70 percent of their repairs during the survey with the camera operator. What they're finding after five years is that they're repairing 90 percent at the well site by the camera operator.

Response: The EPA thanks the commenter for the information that was provided. We agree with the commenter that OGI can be highly effective in finding fugitive emissions when it is used appropriately.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 42

Comment: Good morning. As a solutions provider with proven technology to help reduce methane emissions from the oil and gas sector, Rebellion Photonics stands today to help provide comments on EPA's draft rules in order to ensure it reflects the current state of methane science and technology to address this issue.

We realize that oil and gas companies emit 7 million tons of methane from their operations every year. These emissions are currently projected to increase 25 percent over the next decade. Methane emissions are a significant climate and energy waste problem that's only going to continue to grow. We believe there are ways the draft rules could be improved and our technology could help solve this problem. Gas cloud imaging technology such as Rebellion's photonic camera is available, it's cost-effective, and it's a proven solution for detection and reduction of methane and other VOCs of the installation of new equipment, upgrades, and modified sources in the oil and gas industry.

Rebellion's GCI gas cloud imaging camera employs advanced hyperspectral infrared imaging technology.

We engage in advanced detection algorithms and we employ powerful data storage and transmittal technology. The GCI is different from other leak detectors in the fact that the leak detection is automated. It can be identified and quantified, and we can monitor wide areas from a safe location. With the ability to see the leak, operators can pinpoint the leak and initiate repair on the spot. The GCI also has the potential to catch leaks early and help operators avoid walking into hazardous situations.

We have seen in Colorado where some of the state regulations are the strictest in the country that significant reductions can be made in a cost-effective manner. Our technology, which is an approved instrument there in Colorado by the Colorado Air Quality and Control Commission around their Reg 7 STEM and LDAR program, is cost effective at only $250 per site. This is affordable even for some of the lower-producing wells. We believe that Colorado regulations could be a model for the nation.

Customers there are complying with the law, reducing emissions in a very cost-effective manner. With some of our customers there, we see that we can cover upwards of 25 sites per day, and in one week we have looked at over 1,100 pieces of equipment. Our camera allows for speedy, efficient leak detection with the ability to scan sites easily, and it enables companies to perform inspections more often. It also supports our customers' ability to prioritize those leaks and those repairs and thus reduces the spent labor, time, and the gas losses that we see in the environment.

When putting all of these factors together in dollars and cents, it pays for the service operation of the camera itself. Well site inspections in Colorado have also offered us numerous examples of the importance of more frequent LDAR inspections. We have seen with something as simple as a speed patch that you may look at it today and it may have a dirty seal that's leaking, but you could have looked at it yesterday or a month ago and you wouldn't have seen that very same seal.

A seal that can be leaking now is, again, that random act of nature, so inspecting a piece of equipment appears to be something where you need it on a more increased basis versus a stepdown biannual basis. The importance of follow-up surveys after repair is just as critical to ensure correct maintenance and correct repair of the equipment and to also ensure that one leaky component didn't create another hazard.

Again, this is where Colorado has led the nation in their approach to regulations. They have their companies keep logs of their inspections, their leaks, their first, second, or third attempt at repair, and then finally inspection of that fixed equipment.

Rebellion has created a turnkey approach to this for our customers. We create a web portal for every one of our customers as part of that $250 per site. We store all of their well inspection videos, and we also will then store all of their maintenance logs. In the end, we are finding the forward charge of the EPA and the thought of potentially stricter methane emissions have companies taking note and beginning to implement actions with their sites by utilizing our proven technology and others in an attempt to capture fugitive emissions and reduce lost product.

In the end, lower emissions are good for companies, the industry as a whole, the people of this world, and the environment of all. Thank you.

In response to a question who the commenter represented and the commenter's name, the commenter stated that her name was Amy Allen and that she represented Rebellion Photonics. In response to another question that Ms. Allen had mentioned earlier in her testimony that the technology can also quantify the leaks, Ms. Allen stated that it can. In response to an additional question if Ms. Allen plans to provide information regarding that in public comments, Ms. Allen stated that she could, if needed.

Response: The EPA thanks the commenter for the provided information. We consider the Rebellion GCI and other hyper- or multi-spectral instruments to be OGI instruments. We have changed the requirements of waking path to observation path in order to clarify the allowance of mounted OGI instruments. From our knowledge of the instrument, it should be capable of meeting the requirements of OGI instruments within this rule and not require an alternative means of emissions limitations. This does not eliminate the requirements of the rule such as verification of detection capability or the need maintain line of sight on the fugitive emissions components, which may require multiple vantage points. If this or other similar OGI instruments cannot meet the requirements in the rule such as inability to visualize propane as the indicator for VOCs, the source or owner operator may request an alternative means of emissions limitations. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. We note that the final rule requires the owner or operator to resurvey any component with fugitive emissions once it has been repaired. The final rule also has detailed recordkeeping and reporting requirements.

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 1

Comment: I am commenting on behalf of Infrared Services & Thermal Imaging of Texas, LLC regarding several items in the proposed NSPS OOOOa. Our company is a small business offering both thermal and optical gas imaging (OGI) to clients on a time basis. Our targeted OGI clients are in North Central Texas and Southern Oklahoma, although we have served clients in Louisiana and South Texas.

Our comments will be directed towards issues related to use of OGI technology for control of Fugitive Emissions from Well Sites and Compressor Stations.

Availability of qualified OGI personnel (page 250)-Our company has invested a significant sum of money into the purchase of OGI equipment. When we purchased our equipment in 2011 there were few outside service providers offering OGI, there has been a steady increase in the number of OGI providers. LDAR contractors and environmental consulting firms have purchased OGI devices to supplement other services. In Texas we see the current rate for OGI services at 50% of what rates were in 2009. We can list the names of 15 firms here in Texas that have OGI equipment and trained personal. We believe there is an adequate supply of qualified contractors for small business owners.

Response: The EPA thanks the commenter for the information that was provided. We agree with the commenter on the availability of OGI instruments.

Comment Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 64

Comment Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 57

Comment: In addition, there may be shortages of both the equipment and the trained personnel needed to install the equipment and conduct the fugitive surveys. If many small entities are all simultaneously trying to meet these requirements within a 60-day window, the available staff and contractors with the necessary skills may not be able to service the needs of all of these entities during that time frame. For example, there may not be sufficient personnel trained to properly use OGI technology for surveys, which is particularly problematic given how sensitive the cameras can be to different conditions and settings. It may be particularly hard to find skilled personnel in the remote regions where many well sites and compressor stations are located.

Recommendations:

1. EPA should make the Methane NSPS effective one year after the final rule is issued for all facilities.
2. Alternatively, EPA should extend the effective date for small entities by six months.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Josh W. Luig
Commenter Affiliation: Veritas Energy, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6797
Comment Excerpt Number: 53

Comment: If many small entities are all simultaneously trying to meet these requirements within a 60-day window, the available staff and contractors with the necessary skills may not be able to service the needs of all of these entities during that time frame. For example, there may not be sufficient personnel trained to properly use OGI technology for surveys, which is particularly problematic given how sensitive the cameras can be to different conditions and settings. It may be particularly hard to find skilled personnel in the remote regions where many well sites and compressor stations are located.

Recommendations:
1. EPA should make the Methane NSPS effective one year after the final rule is issued for all facilities.
2. Alternatively, EPA should extend the effective date for small entities by six months.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Comment Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 51

Comment Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 52

Comment Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 103

Comment Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 52

Comment: In addition, there may be shortages of both the equipment and the trained personnel needed to install the equipment and conduct the fugitive surveys. If many small entities are all simultaneously trying to meet these requirements within a 60-day window, the available staff and contractors with the necessary skills may not be able to service the needs of all of these entities during that time frame. For example, there may not be sufficient personnel trained to properly use OGI technology for surveys, which is particularly problematic given how sensitive the cameras can be to different conditions and settings. It may be particularly hard to find skilled personnel in the remote regions where many well sites and compressor stations are located.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 21

Comment: Limited OGI contractor resources will likely delay compliance efforts for small business entities.

Competition for limited contractor resources will likely reduce the ability of small business entities to schedule semiannual OGI LDAR surveys and may affect their ability to comply with the requirement in a timely manner. Larger regulated entities subject to Subpart OOOOa will generally have larger holdings (and budgets) resulting in larger contracts and likely preferential scheduling of contractor resources. Allowing the use of alternative LDAR compliance methods (i.e., EPA Method 21) will mitigate this concern and allow many small business entities to continue to use LDAR technology that they know and which, as noted, is at least as effective to identify, quantify, and document repairs to leaking components as OGI technology.

Response: The EPA is allowing the use of Method 21 in addition to OGI in the final rule. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more detail regarding this issue. We have also included language in the final rule that allows for the approval of emerging technologies for reducing fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. Concerning the availability of OGI contractors, see response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 18

Comment: My concern is for the smaller operators that may only have several wells and a basin. They're not going to be able to meet these time frames for the initial survey but also for any resurveys. Because if someone calls us, we're going to go to the guy that has 50 wells to do, not a guy that has five wells to do.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12, and DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 21.

Commenter Name: Jim Disser, VP Sales
Commenter Affiliation: Diamond Technical Surveys, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6938
Comment Excerpt Number: 1

Comment: Our company is Diamond Technical Surveys, LLC, located in Spring TX. We are an infrared service provider, in business over 15 years. We offer traditional infrared services (electrical, mechanical, industrial and commercial markets) all over the U.S., offshore, and internationally. Currently we do not own an Optical Gas Imaging (OGI) camera. If this ruling passes, we would strongly consider adding OGI to our service offerings.

Response: The EPA thanks the commenter for the provided information. We are finalizing the rule with OGI as one technique for finding fugitive emissions.

Comment Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 24

Comment Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 21

Comment Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 22

Comment Name/Affiliation: W. Jeffrey Spark / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 22

Comment Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 23

Comment Name/Affiliation: Rick D. Davis, Jr / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 22

Comment Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 21

Comment: EPA has also failed to consider the impact that the short time periods included in the rule will have on small entities. As previously discussed, these entities have many small well or compressor sites spread out over large geographic areas. The Methane NSPS creates an endless cycle of tight compliance deadlines that will strain the resources of small entities: first the operators must complete fugitive emissions surveys within 30 days of start-up or modification, then semi-annual or even quarterly surveys, followed by repairs within 15 days of the survey, followed by a follow-up survey within 15 days of the repair. The affected small businesses will have to repeat these requirements at each of their dispersed sites, as well as the recordkeeping and reporting requirements. EPA should have considered the impact that these tight timelines place on small entities and offered extended timelines for those entities.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12, for information regarding initial monitoring surveys. Additionally, the final rule provides a longer time for leaks to be repaired and resurveyed. See sections VI.F.1.e and VI.F.2d of the preamble to the final rule for more details regarding this issue. Finally, we have added the use of Method 21 as an alternative to OGI for fugitive emissions monitoring. This will provide small businesses flexibility to choose the most cost-effective monitoring instruments for their fugitive emissions monitoring program. We believe these changes address most of the commenter's concerns about the impacts on small businesses.

Comment Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 60

Comment Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 50

Comment Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 51

Comment Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 51

Comment: The Methane NSPS's effective date does not give oil and gas operators sufficient time to make necessary equipment upgrades, hire and train new personnel, and complete the required initial surveys.

The Methane NSPS only gives operators 60 days from the time the final rule is issued to come into compliance with its requirements. If the proposed Methane NSPS is any indication, the final rule will also be lengthy and highly technical. In addition, the Methane NSPS will require operators to scale up their operations by hiring and training new personnel to complete the fugitive survey monitoring, reporting, and recordkeeping requirements, and to ensure that their equipment complies with the new control rules. Operators will not know until the final rule is released what the exact requirements will be, and therefore cannot plan and prepare to implement the rule until it is issued. Assessing and complying with the new requirements within 60 days will be particularly difficult for small upstream entities, as they are unlikely to have existing personnel with experience in federal air regulations, and will have to assess compliance requirements at many well sites.

Recommendations:

1. EPA should make the Methane NSPS effective one year after the final rule is issued for all facilities.
2. Alternatively, EPA should extend the effective date for small entities by six months.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Comment Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 51
Comment Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 102

Comment: The Methane NSPS only gives operators 60 days from the time the final rule is issued to come into compliance with its requirements. If the proposed Methane NSPS is any indication, the final rule will also be lengthy and highly technical. In addition, the Methane NSPS will require operators to scale up their operations by hiring and training new personnel to complete the fugitive survey monitoring, reporting, and recordkeeping requirements, and to ensure that their equipment complies with the new control rules. Operators will not know until the final rule is released what the exact requirements will be, and therefore cannot plan and prepare to implement the rule until it is issued. Assessing and complying with the new requirements within 60 days will be particularly difficult for small upstream entities, as they are unlikely to have existing personnel with experience in federal air regulations, and will have to assess compliance requirements at many well sites.

Recommendations:

1. EPA should make the Methane NSPS effective one year after the final rule is issued for all facilities.
2. Alternatively, EPA should extend the effective date for small entities by six months.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Josh W. Luig
Commenter Affiliation: Veritas Energy, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6797
Comment Excerpt Number: 52

Comment: The Methane NSPS only gives operators 60 days from the time the final rule is issued to come into compliance with its requirements. If the proposed Methane NSPS is any indication, the final rule will also be lengthy and highly technical. In addition, the Methane NSPS will require operators to scale up their operations by hiring and training new personnel to complete the fugitive survey monitoring, reporting, and recordkeeping requirements, and to ensure that their equipment complies with the new control rules. Operators will not know until the final rule is released what the exact requirements will be, and therefore cannot plan and prepare to implement the rule until it is issued. Assessing and complying with the new requirements within 60 days will be particularly difficult for small upstream entities, as they are unlikely to have existing personnel with experience in federal air regulations, and will have to assess compliance requirements at many well sites.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Comment Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 14

Comment Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 16

Comment Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 14

Comment Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 14

Comment Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 15

Comment: The Methane NSPS's effective date does not give oil and gas operators sufficient time to make necessary equipment upgrades, hire and train new personnel, and complete the required initial surveys.

The Methane NSPS only gives operators 60 days from the time the final rule is issued to come into compliance with its requirements. If the proposed Methane NSPS is any indication, the final rule will also be lengthy and highly technical. In addition, the Methane NSPS will require operators to scale up their operations by hiring and training new personnel to complete the fugitive survey monitoring, reporting, and recordkeeping requirements, and to ensure that their equipment complies with the new control rules. Operators will not know until the final rule is released what the exact requirements will be, and therefore cannot plan and prepare to implement the rule until it is issued. Assessing and complying with the new requirements within 60 days will be particularly difficult for small upstream entities, as they are unlikely to have existing personnel with experience in federal air regulations, and will have to assess compliance requirements at many well sites.

In addition, there may be shortages of both the equipment and the trained personnel needed to install the equipment and conduct the fugitive surveys. If many small entities are all simultaneously trying to meet these requirements within a 60-day window, the available staff and contractors with the necessary skills may not be able to service the needs of all of these entities during that time frame. For example, there may not be sufficient personnel trained to properly use OGI technology for surveys, which is particularly problematic given how sensitive the cameras can be to different conditions and settings. It may be particularly hard to find skilled personnel in the remote regions where many well sites and compressor stations are located.

Recommendations:

1. EPA should make the Methane NSPS effective one year after the final rule is issued for all facilities.

2. Alternatively, EPA should extend the effective date for small entities by six months.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12, for information regarding initial monitoring surveys. Additionally, we have added the use of Method 21 as an alternative to OGI for fugitive emissions monitoring. This will provide small businesses flexibility to choose the most cost-effective monitoring instruments for their fugitive emissions monitoring program.

Commenter Name: Domestic Energy Producers Alliance
Commenter Affiliation: Domestic Energy Producers Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-5425
Comment Excerpt Number: 3

Comment: The leak detection and repair requirement in the methane rule will require DEPA members to hire additional personnel to ensure compliance – an unnecessary cost they can ill afford today. Fugitive emissions from oil and gas production equipment sources have historically accounted for relatively small proportion of VOC or methane emissions. Emissions using factors provided by the EPA under the AP-42 publication have yielded calculated emissions representing less than 3% of the total hydrocarbon emissions form these facilities. The benefit of implementing the leak detection and repair (LDAR) program on these relatively small facilities would not even be measurable in the overall scheme of hydrocarbon emissions, and especially for methane emissions that will have questionable impact on the GHG effect.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 28.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 20

Comment: The required use of OGI technology will impose excessive financial burdens on small business entities.

Small business entities within the oil and gas sector typically do not have the financial resources to purchase OGI LDAR monitoring equipment and will need to rely on outside contractors. PIOGA anticipates that the demand for such services will increase dramatically if the Subpart OOOOa regulations are promulgated as they are proposed and will allow such entities to charge a premium for their services. Given the current price of natural gas (2.15 \$/Mcf – NYMEX December 2015) and the, as noted, basis differential faced by many Pennsylvania producers, the additional costs could threaten the very survival of our members.

Response: In the final rule, the EPA has added Method 21 as an option for conducting fugitive emissions monitoring surveys. We believe that many small businesses will utilize this option by either performing the Method 21 surveys themselves or hiring a contractor. We believe this provides small entities with enough options to address the commenter's concerns.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 68

Comment: With the sheer number of valves, connectors, pressure release devices, pumps, seals, diaphragms, all of which you've listed there, and there can be several dozen in each facility, it is highly labor-intensive to implement, report, and replace, document, change, and repair status across hundreds or thousands of facilities. Sophisticated large producers may have the IT and accounting -- and accounting capabilities, but this capability does not exist in smaller companies.

Response: As summarized in our response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt28, methane and VOC emissions from fugitive emissions are considerable, and as such, we believe it is necessary to reduce these emissions. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

The EPA has made several changes to the fugitive emissions monitoring requirements that directly reduce the burden on small entities. See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12, for information regarding initial monitoring surveys. Additionally, the final rule provides a longer time for leaks to be repaired and resurveyed. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more details regarding this issue. Finally, we have added the use of Method 21 as an alternative to OGI for fugitive emissions monitoring. This will provide small businesses flexibility to choose the most cost-effective monitoring instruments for their fugitive emissions monitoring program.

Commenter Name: Anthony J. Ferate
Commenter Affiliation: Oklahoma Independent Petroleum Association (OPIA)
Document Control Number: EPA-HQ-OAR-2010-0505-6810
Comment Excerpt Number: 5

Comment: OGI instruments are expensive and the cost is excessive for small operators. Small operators may not be able to find vendors available to survey a small number of wells within the required timeframe. Small operators will be also unfairly burdened with a higher cost of compliance because service firms cannot offer discounts on single site surveys versus visiting multiple sites (for larger operators) per day. EPA should recalculate costs based on actual equipment and vendor costs.

Response: The EPA has revised the cost estimate based on changes to the final rule. See the TSD to the final rule for more information on costs.

We have made several changes to the fugitive emissions monitoring requirements that directly reduce the burden on small entities. See response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12, for information regarding initial monitoring surveys. Additionally, the final rule provides a longer time for leaks to be repaired and resurveyed. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more details regarding this issue. Finally, we have added the use of Method 21 as an alternative to OGI for fugitive emissions monitoring. This will provide small businesses flexibility to choose the most cost-effective monitoring instruments for their fugitive emissions monitoring program.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 41

Comment: Compressor Stations. EPA's cost-effectiveness estimates for LDAR at compressor stations are more aligned with previous analyses and demonstrate that more frequent, quarterly LDAR is cost-effective at these facilities. Nonetheless, EPA proposes semi-annual monitoring on the grounds that more frequent monitoring may constrain the availability of survey contractors, which may, in turn, adversely affect small businesses. 80 Fed. Reg. at 56,641. EPA cites the same rationale as a basis for its alternative proposal to require annual monitoring at well sites. *Id.* at 56,637.

EPA's rationale is flawed. Indeed, the agency's proposal is based on the premise (lacking factual support) that demand for LDAR contractors and equipment will outpace supply, leading to higher costs and adverse impacts for small businesses. However, prior experience and data suggest the opposite to be true: technology providers can quickly and efficiently respond to signals created by clean air standards. Indeed, this has been true where standards have forced *development* of new technologies, and is certainly the case where these technologies already exist and must simply be deployed more broadly.

In addition to this time-tested reality, EPA's rationale ignores circumstances related to these particular sources. With respect to compressor stations, EPA's TSD projects that, in 2020, 259 new gathering and boosting stations, six new transmission stations, and 15 new storage stations will be subject to the compressor station LDAR requirements. This extremely small number of new sources is unlikely to drive any imbalance between supply and demand.

This is especially true given that some compressor stations in these segments are already deploying leak detection technology to comply with existing state and federal standards. Indeed, Colorado requires LDAR at new and existing gathering and boosting compressor stations, while EPA's Reporting Rule requires new and existing transmission compressor stations and underground and LNG storage facilities to undertake annual leak surveys using OGI and other technologies. *See* 40 C.F.R. §98.232(e)(7), §98.232(f)(5), §98.232(g)(3), and §98.233(q). Colorado has projected that its standards would apply to 200 compressor stations, and EPA's most recent Reporting Rule data suggest that over 300 facilities completed such surveys.

Pennsylvania has also required quarterly LDAR using OGI at gas processing plants and compressor stations since 2013. It is simply erroneous to suggest that quarterly inspections at approximately 300 new facilities—or 1,200 new inspections—could not be completed in light of the breadth of sources already deploying these technologies. Moreover, though EPA projects a greater number of well sites will be subject to new LDAR standards, as discussed above, Colorado, Pennsylvania, Utah, Wyoming, and Ohio have had LDAR requirements in place for some time, and there has been no evidence of supply issues or adverse impacts to small businesses, including in states or areas where LDAR is required more often than semi-annually.

Finally, even if the agency receives rigorous, quantitative data suggesting that limited contractor availability may impact small businesses, it is nonetheless arbitrary for EPA to respond to these concerns by weakening clean air standards for *all* sources and in perpetuity. Indeed, in numerous other circumstances, including in recent oil and natural gas sector rulemakings, EPA has retained rigorous clean air standards, but phased those standards in to ensure adequate availability of pollution control measures. *See, e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule, 77 Fed Reg. 49,498, 49,513 (August 16, 2012), codified at 40 CFR Parts 60 and 63 (creating a one year phase-in period for storage vessel controls, pneumatic controllers, and RECs). At most, a limited phase-in may be appropriate here, and only if substantiated by rigorous technical information. Accordingly, as we describe below, EPA must strengthen frequency requirements for both compressor stations and well sites.

Response: The EPA thanks the commenter for the provided information. In response to comments, we reevaluated the compressor station fugitive emissions monitoring requirements and impacts. Based on the results of the analysis, the final rule now requires quarterly monitoring on a fixed schedule for compressor stations. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, and section VI.F.2.a of the preamble to the final rule for more detail regarding this issue. Concerning the supply of OGI equipment and contractors, see response to DCN EPA-HQ-OAR-2010-0505-6793, Excerpt 12.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 25

Comment: We found the cost of operating the OGI program to be very affordable even for smaller producers and low-producing wells. In a survey of consultants that offer third-party services, we have seen prices in the range of 250 to $350 per site survey. When surveying people with in-house programs, they're running about half that rate in the 150 to $170 per site survey.

Response: The EPA appreciates the commenter's input.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 43

Comment: Accordingly, EPA needs to base the initial survey on a sufficient period of time after the startup of production. It should not be based on the date of well completion.

Response: The EPA agrees with the commenter and has revised the final rule to stipulate that the beginning of the initial compliance period for well sites is the startup of production. Paragraphs 60.5397a(f)(1) and (2) now state that you must conduct an initial monitoring survey within 60 days of the startup of production, as defined in §60.5430a, for each collection of fugitive emissions components at a new well site or compressor station or within one year after the date of publication of the rule in the Federal Register, whichever is later. See sections VI.F.1.g and VI.F.2.f of the preamble to the final rule for more detail regarding this issue.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 26

Comment: The Proposed Rule requires OGI for leak detection, and EPA requests comments on whether additional methods should be allowed. PAW strongly supports flexibility in the leak detection methods allowed for surveying or resurveying repaired components. EPA should allow for the use of Method 21 including soap bubbles as outlined in section 8.3.3, OGI, or infrared laser beam illuminated instruments as options for leak surveys or resurvey for verification of repair. Soap bubbles in particular should be allowed as it is a benefit to operators particularly small operators with few or small sites where other methods are not cost effective particularly for small sites with component numbers well below EPA's model plant. Particularly for repair verification, soap bubbles are already approved in method 21 due to its effectiveness, and this method doesn't require the costly use of trained OGI operators and crews to resurvey a single repair.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 185

Comment: In addition, EPA should allow the use of soap bubbles for leak detection, since EPA approves Method 21 for repair confirmation and emissions quantification is not required under OOOOa. According to Section 8.3.3 of Method 21, leaks may be screened using the presence of soap bubbles. If bubbles are not observed, then the source is assumed to have no detectable emissions under Method 21. EPA allows the use of 8.3.3 for other industries including chemicals and refining. It should be allowed here too. The leaks may not be repaired by the same person doing the leak survey. Allowing the soap bubble test would allow the person doing the repair to check the repair without requiring the leak survey person to have to go out to the site for a second time. This would reduce the time and expense required for doing repairs.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 20

Comment: For small operators, the cost of an OGI or Method 21-based LDAR program will be particularly burdensome. In some instances, these small operators have only a few wells or wells with low production volumes; and therefore the cost of the equipment or implementing the program may vastly exceed the emissions being saved. As an alternative to expensive instrumental surveys, we recommend that EPA allow for soap bubbles as a potential screening method (only where appropriate, considering the caveats in Section 8.3.3.1). EPA already recognizes the effectiveness of soap bubbles in its Method 21, Section 8.3.3 procedure.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 22

Comment: Lastly, MarkWest also recommends that EPA allow for soap bubbles as a potential screening method (only where appropriate, considering the caveats in Section 8.3.3.1), as an alternative to expensive instrumental surveys. EPA already recognizes the effectiveness of soap bubbles in its Method 21, Section 8.3.3 procedure.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 86

Comment: It is also important that in allowing Method 21, EPA include the alternative “bubble check” screening procedure for fugitive emission monitoring. The alternative EPA approved procedure provided in Section 8.3.3 of Method 21 is based on the formation of bubbles in a soap solution that is sprayed on a potential leak source. The bubble check procedure may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. For flanges, connectors and certain other fugitive emission components, a leak may be defined by the formation of bubbles in soap solution. Subsequently, the elimination of the formation of bubbles indicates no leak. In sum, the option to perform Method 21, including the alternative bubble check procedure, should be allowed to provide flexibility and a reasonable cost-effective alternative to OGI.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Kari Cutting
Commenter Affiliation: North Dakota Petroleum Council (NDPC)
Document Control Number: EPA-HQ-OAR-2010-0505-6789
Comment Excerpt Number: 23

Comment: At a minimum, EPA should amend its proposed fugitive emissions work practices to allow operators the flexibility to use Method 21 for the initial survey, and any method for resurveying under Method 21 (including soap bubbles) upon re-survey. This would provide a more "feasible" and "practicable" work practice that would still achieve the same objectives as the current Proposed NSPS OOOOa standard.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.

Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 58

Comment: In addition, operators need even greater flexibility regarding repair verification, consistent with existing regulatory programs including NSPS Subparts VV and VVa. Kinder Morgan proposes that any methodology available under these subparts to determine that leaks have been repaired, including soapy water, should be available under any final NSPS OOOOa to confirm that a leak has been repaired. After a specific location of the leak has been determined, targeted, simple and easy methodologies are appropriate for repair confirmation, while being cost-effective and providing significant flexibility to the operator.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 251

Comment: The sub solution of a spray bottle is a viable alternative. We have used it in the past. It's a good alternative.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Cyrus Reed, Conservation Director
Commenter Affiliation: Lone Star Chapter, Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-5418
Comment Excerpt Number: 8

Comment: Finally, while the proposal requires that operators repair leaks within 15 days of discovery, they allow up to six months for instances in which "safety" is not an issue. This is simply too long an exception. Instead, EPA should grant no more than 60 days for the safety exception. If operators have not removed the hazard by that point, they should be required to shut-down operations at that point in order to repair the leak.

Response: The EPA does not agree with the commenter. Based on available information, the likelihood of an emergency blowdown or a compressor station shutdown occurring within six months of finding fugitive emissions from a component may be low, and it may be two years before a well is shut-in or shutdown or the next scheduled or emergency compressor blowdown or compressor station shutdown. Requiring a shutdown or blowdown could result in greater emissions than what would be emitted by the leaking component. Therefore, to avoid the excess emissions (and cost) of prematurely forcing a shutdown or causing potential harm to workers, we are amending the rule to allow a delay of repair of 2 years to fix a leak where it is technically infeasible to fix the component without a blowdown or shutdown of the compressor station or it would be unsafe to repair by exposing personnel to immediate danger; however, if an unscheduled or emergency vent blowdown, compressor station shutdown, well shutdown, well shut-in occurs during the delay of repair period, the fugitive emissions components would need to be fixed at that time. The owner or operator will have to record the number and types of components that are placed on delay of repair and record an explanation for each delay of repair. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more detail regarding this issue.

Commenter Name/Affiliation: J. Young; Citizen
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6469; 8

Commenter Name/Affiliation: T. Bacci; Citizen
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6471; 6

Commenter Name/Affiliation: S. Hathaway; Citizen
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6473; 5

Comment: We urge you, even knowing that it's futile, to improve the proposed rules to include:

Shortening the time source operators have to repair leaking equipment if it would be unsafe to make the repair within 15 days of discovery;

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Robert M. Gould
Commenter Affiliation: San Francisco Bay Area Physicians for Social Responsibility (SF Bay PSR)
Document Control Number: EPA-HQ-OAR-2010-0505-6819
Comment Excerpt Number: 10

Comment: In addition, the proposal allows companies up to six months to repair leaking equipment if the companies say it would be unsafe to make the repair within 15 days of discovery. Operators must be required to find a safe way to fix leaks in a much shorter period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: David M. Babson
Commenter Affiliation: Union of Concerned Scientists (UCS)
Document Control Number: EPA-HQ-OAR-2010-0505-6858
Comment Excerpt Number: 5

Comment: Finally, allowing a 15 day leak repair time to be extended to 6 months for any reason is unacceptable. Operators should be required to find a "safe" way to fix leaks in a reasonable period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8. Additionally, we note that owners and operators cannot claim just any reason in order to delay repairs. The repair can only be delayed if the component cannot be fixed without a shutdown or blowdown or if the repair would expose personnel to immediate danger. This number and type of components for which repair is delayed, along with the explanation on why the repair was delayed must be included in the annual report, which is submitted electronically to the EPA.

Commenter Name: Colleen Cooley
Commenter Affiliation: Diné Citizens Against Ruining Our Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6883
Comment Excerpt Number: 4

Comment: In addition, the proposal would allow oil and gas companies up to six months to repair leaking equipment if the companies say it would be unsafe to make the repair within 15 days of discovery. This is too long: People living near these facilities should not have to live with leaks for months on end. Operators should be required to find a safe way to fix leaks in a reasonable period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Jennifer Cassel, Staff Attorney
Commenter Affiliation: Environmental Law & Policy Center
Document Control Number: EPA-HQ-OAR-2010-0505-6994
Comment Excerpt Number: 6

Comment: Specifically, as delineated by our colleague Earthworks in their separate comments on this proposed rule, the draft rule should be revised to include:

- A shorter period of time for operators to repair leaking equipment if it would be unsafe to make the repair within 15 days of discovery;

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Julie Archer, Project Manager; and David McMahon, J.D., Co-Founder
Commenter Affiliation: West Virginia Surface Owners' Rights Organization (WVSORO)
Document Control Number: EPA-HQ-OAR-2010-0505-7066
Comment Excerpt Number: 9

Comment: In addition, we urge you to improve the proposed rules to:

Shortening the time source operators have to repair leaking equipment if it would be unsafe to make the repair within 15 days of discovery;

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Interfaith Center on Corporate Responsibility (ICCR)
Commenter Affiliation: Interfaith Center on Corporate Responsibility (ICCR)
Document Control Number: EPA-HQ-OAR-2010-0505-7068
Comment Excerpt Number: 8

Comment: It is important that leaks be repaired as quickly as possible. The proposal would allow oil and gas companies up to six months to repair leaking equipment if the companies say it would be unsafe to make the repair within 15 days of discovery. Communities living near these facilities should not have to live with leaks for months on end. Operators should be required to find a safe way to fix leaks in a reasonable period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6858, Excerpt 5.

Commenter Name: Terry Lansdell, Program Director
Commenter Affiliation: Clean Air Carolina
Document Control Number: EPA-HQ-OAR-2010-0505-7241
Comment Excerpt Number: 4

Comment: Shortening the time source operators have to repair leaking equipment if it would be unsafe to make the repair within 15 days of discovery.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania

Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 7

Comment: I'd also urge the proposed repair -- repair period of six months for leaks that can't be readily fixed within 15 days, be shortened. Six months is too long to be allowing increased exposure and environmental damage from the release of methane and other volatile organic compounds.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 66

Comment: And finally, a six-month period to allow source operators to repair leaking equipment is much too long a period of time. The danger to health, air quality, and climate change is far too important to allow leaks to continue for six months.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 161

Comment: We also ask you to shorten the period that operators have to fix leaks. Six months may be convenient for operators. But nearby residents will suffer the consequences of ongoing exposure. As long as leaks remain unaddressed, emissions levels and pollution will worsen. Days of exposure is already a risky period. Months is simply unconscionable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM -

8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 209

Comment: While we support the regulations, we join with other commenters who call for the following changes to be made: Allowing oil and gas operators up to six months to repair leaking equipment if the companies say that it would be unsafe to make the repairs in 15 days is too long. Operators should be required to find a safe way to fix leaks in a reasonable period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6858, Excerpt 5.

Commenter Name: Patricia Karr Seabrook
Commenter Affiliation: Miller/Howard Investments, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6818
Comment Excerpt Number: 5

Comment: It is important that leaks be repaired as quickly as possible. The proposal would allow oil and gas companies up to six months to repair leaking equipment if the companies say it would be unsafe to make the repair within 15 days of discovery. Communities living near these facilities should not have to live with leaks for months on end. Operators should be required to find a safe way to fix leaks in a reasonable period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6858, Excerpt 5.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 111

Comment: Basically, we want to shorten the time frames that you allow them to respond to these things. Right now, you have, like, six months for them to respond to an incident if it's not an emergency. We need to reduce that.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00

AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 118

Comment: Inspections should be more frequent, and the leaks that are found should be fixed faster.

Response: In the final rule, the EPA has changed the fugitive emissions monitoring survey frequency from a variable, performance based approach to fixed frequency. Well sites must perform surveys semiannually and compressor stations quarterly.

We disagree that leaks should be repaired faster than the proposed 15-day period. Based on comments received, we are finalizing a 30-day period to repair and resurvey leaks because repairs for some sources of fugitive emissions at a well site or compressor station may take multiple attempts or require additional equipment that is not readily available and may take longer than 15 days to repair. Well sites and compressor stations, unlike chemical plants or refineries, may be located in remote areas and may not have warehouses or maintenance shops nearby where spare equipment or tools are kept that would be needed to perform repairs within 15 days. While we are allowing for a 30-day repair timeframe, we acknowledge that some state LDAR programs require repairs to be made within 15 days of finding a leak. In those cases, equipment that cannot be repaired within 15 days are given additional time to obtain replacement parts, which we believe is consistent with our 30-day timeframe. Owners and operators should attempt to fix components as soon as practicable, and as such, we do expect that the majority of components will not need the additional 15 days for repair. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more detail regarding this issue.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 84

Comment: In addition, the proposal would allow oil and gas companies up to six months to repair leaking equipment. This is too long. Operators should be required to find a safe way to fix leaks in a reasonable period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM -

11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 85

Comment: And, again, regardless of whether or not leaks are detected in previous inspections. We'd like to, again, shorten the amount of time to fix leaking equipment that's detected. Six months is far too long.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.;
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 38

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 34

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 35

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc.
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 35

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 36

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 35

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 24

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 29

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 26

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 25

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 72

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 30

Comment: Alternatively, the Rules should provide 30 days for resurveys to be performed after repairs.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 53

Comment: We recommend that upon receipt of the auditor's report the source corrects any deficiencies detected or observed within 30 days. 30 days provides a sufficient time frame to correct deficiencies. Generally, if an operator is complying with the standards, there should neither be any surprises nor major repairs. Operators generally have relationships with contractors that if they are unable to do the repair with company personnel they are able to hire a contractor fairly quickly.

Response: The EPA is not finalizing requirements for auditing fugitive emissions monitoring programs. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more detail regarding repair times.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 130

Comment: EPA solicited comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. Many leaks detected can be repaired on site with simple tightening of screwed connections, or replacement of small components carried by the maintenance team if authorized maintenance personnel are available around the time of the survey. Fifteen days is adequate in these circumstances. However some leaks require more time to repair due to safety issues, availability of replacement parts, availability of maintenance personnel, weather conditions, or other issues related to the sites being remote, dispersed, and unmanned facilities. Also, the availability of training LDAR staff to re-monitor and validate that the component is indeed repaired is another logistical reason that more time is needed. Thus, API requests that 30 days be provided to complete the repairs.

The Current Proposal Does Not Allow For Multiple Attempts To Repair Identified Leaks.

In the proposed regulation, EPA requires discovered leaks to be repaired within 15 days. Multiple attempts to repair may be required to repair such that 15 days is not be adequate to make a successful repair. Provisions are needed to allow for occurrences where complex leaks cannot be fixed within 15 days. These may be situations where additional engineering and analysis is required to develop the safe and correct solution to repair the leak. There needs to be sufficient regulatory flexibility to address instances where several repair attempts are needed until the leak is repaired.

EPA should provide appropriate provisions to accommodate situations where multiple attempts are required to repair a leak.

Recommended Text Revisions Related To Work Practices/Inspections

§60.5397a(e) Each monitoring survey shall observe each piece of equipment with fugitive emissions components for fugitive emissions. (f)(1) You must conduct an initial monitoring survey within ~~30~~180 days of the first date of production ~~well completion~~ for each collection of fugitive emissions components at a new well site ~~or upon the date the well site begins the production phase for other wells~~. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within ~~30~~180 days of the well site modification.

§60.5397a(f)(2) You must conduct an initial monitoring survey within ~~30~~180 days of the startup of a new compressor station or central production site for each new collection of fugitive emissions components at the new compressor station or central production site. For modified compressor stations or central production sites, the initial monitoring survey of the collection of fugitive emissions components at a modified compressor station or central production site must be conducted within ~~30~~ 90 days of the modification. For affected facility compressor station or central production sites constructed between Sept. 18, 2015 and 60 days after [final date of rule], initial surveys must be completed by [insert one year and 60 days after final rule promulgation]

§60.5397a(j)(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than ~~15~~30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe ~~to repair during operation of the unit~~, the repair or replacement must be completed during the next scheduled shutdown ~~or within 6 months, whichever is earlier~~.

§60.5397a(j)(2)(ii)(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than ~~500~~10,000 ppm above background.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 14

Comment: Repair time for leaking components. The TCEQ generally supports the proposed 15 day repair time. The time period should be sufficient for most repairs. However, the 15 day repair time will probably not be long enough for some circumstances when multiple trips are required to obtain all of the materials necessary for the repair, when there are long lead times for any unique or special parts that must be ordered, or when weather or transportation difficulties are encountered, etc. The TCEQ recommends that for sites not located in an ozone nonattainment area, and where the total uncontrolled potential to emit from all components is less than 10 tons per year, the allowed time period for repair should be extended to 30 days after the leak is detected for manned sites, and 60 days after the leak is detected for unmanned sites.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 200

Comment: Repair times to correct leaks should not be permitted to exceed 30 days.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 14

Comment: Survey Frequency: Overall, the proposed LDAR survey schedule is too frequent to be effective. As proposed, operations must resurvey leak locations within 15 days to certify that these detected leaks have been repaired. This limited time period is not feasible in many field situations. Apache recommends a 30-days repair time and repair verification made by OVA or soap bubble method. LDAR resurvey would occur at the next regularly scheduled interval. This time period is much more realistic in order to meet emission reduction strategies.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 15

Comment: The proposed rules require a "resurvey" after completion of repairs. As we understand the proposed rule, Operators have the flexibility to resurvey the repair with the OGI or Method 21 (including soap bubble method). The "resurvey" is to be conducted within 15-days of the repair. SWN's fugitive emissions monitoring experience indicates that the significant majority of leaks can be repaired upon initial observation and the resurvey can be completed "concurrently". However, for those repairs which require additional time, a 15 day resurvey timeframe could incur increased cost if a fugitive emissions team needs to be mobilized for the purpose of resurveying "a single leak". As with aggregating the initial (and annual) fugitive emission surveys, an increased timeframe allowing multiple "resurvey's" of repaired leaks would result in lower implementation costs and increased efficiencies.

Recommendation:

We also recommend that EPA revise the resurvey timeframe from 15 days to either 30 days or 60 days (again to allow aggregating resurveys).

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 50

Comment: Under the proposal, an owner or operator would be required to repair or replace a source of fugitive emissions "as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions." EPA solicits comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. EPA indicates that it is proposing the 15-day period because that is the period of time it has historically allowed for repair/resurvey in LDAR programs, and that this indicates such timing would be appropriate here as well, in addition to citing the number of components at a well site and the number that would need to be repaired." The same rationale is used to support a 15-day requirement for compressor stations.

At least 30 days should be provided for repair and re-monitoring under these provisions. Moreover, extensions should be available for remotely located well-sites and compressor stations. While EPA has typically had 15-day periods for repair and re-monitoring in other rules, those rules apply at operating plants that contain numerous process units and are continuously staffed. The unique characteristics of the oil and gas industry need to be taken into consideration in establishing schedules. In addition, remote well sites present an even more unique case. The rule needs to take into account the remoteness of sites and the difficulties that owners and operators may face at certain times of year due to weather and resource availability in reaching these sites and achieving repair and re-monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 37

Comment: Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

1. Fugitive Emissions From Well Sites

We recommend that sources of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. 15 calendar days is a reasonable timeframe as the operator needs to have a sufficient program of maintenance and repairs that would provide for prompt action within 15 calendar days. Operators and their personnel are on a 24/7/365 schedule, so again, 15 calendar days provides a sufficient timeframe for the repair or replacement to be completed. Additionally, we recommend that any fugitive emission source that has the potential to create or is a public health and safety threat must be immediately repaired.

2 Fugitive Emissions From Compressor Stations

We recommend that 15 days is an appropriate amount of time for repair of sources of fugitive emissions at compressor stations. Many operators have at least day shift personnel on site daily and sufficient staffing to be able to complete a repair within the 15 days. It is in the operators best interest to do prompt repairs, and when motivated financially – they've demonstrated they are able to do major repairs quickly. For example, the Lathrop Compressor Station located in Springville Township, Susquehanna County suffered from an explosion as a result of human error during maintenance (2012). The operator had the facility returned to operations within several days lacking PA DEP approval. So, when an operator wants to return a facility to operations post haste, they do it. (Article regarding this event is attached at the end of our comment.)

[Susquehanna County Explosion Report Press Release Below]

http://thedailyreview.com/news/state-releases-susquehanna-county-compressor-explosion-report-1.1299720

State releases Susquehanna County compressor explosion report

BY LAURA LEGERE (TIMES-SHAMROCK WRITER)

Published: April 14, 2012

A worker who heard gas flowing from an open valve on a Susquehanna County compressor engine pulled an emergency shutdown switch as he evacuated the station, stopping the flow of gas to the building just before it exploded, according to a report by Williams Partners released Friday by state regulators.

The report detailing events before and after the blast and fire at the Lathrop compressor station in Springville Twp. on March 29 was submitted to the Department of Environmental Protection on April 7. Williams said a worker did not properly lock down a compressor when he was away from the engine during maintenance and two other workers, who assumed the work was done, began to turn the engine back on.

Although the account revealed new details about the incident, it left unanswered some questions sought by state environmental regulators and raised new ones.

The report does not explain what ignited the gas trapped in the compressor.

It also appears to contradict earlier reports from Williams that automatic shutdown procedures were triggered by the flow of gas into the building. According to the report, "One of the workers pulled the (emergency shutdown) button on his way out of the building."

DEP responded to the report with more than a dozen questions for Williams to clarify, a department spokeswoman said Friday.

Williams' explanation of the shutdown procedure and missing information about the source of the explosion were among the areas of concern highlighted by the agency, spokeswoman Colleen Connolly said.

No one was injured in the blast and fire at the station, but the explosion tore part of the roof and sides from the building, rattled nearby homes and drew emergency response crews from three counties - including the Chinchilla Hose Company's specialized foam trailer that had to travel there from South Abington Twp.

The incident also raised concerns about the safety and oversight of the natural gas infrastructure which, because it is in a rural area, is not regulated like pipelines and compressors in more populated places. DEP and Williams will hold a public briefing about the explosion on Tuesday evening at Montrose High School. Williams spokeswoman Helen Humphreys said Friday that there are "multiple manual switches, multiple gas detectors and multiple fire detectors" at the Lathrop compressor building "any one of which could have triggered the emergency shutdown system."

Although Williams initially thought the gas detection system triggered the shutdown, she said, it found during its investigation that a manual switch was pulled first, "within seconds of the release" of gas.

The report revealed a clearer picture of the scene at the station on the day of the blast: After workers mistakenly turned on the engine that was shut down for maintenance, three workers training on a nearby engine heard the leaking gas and left the building.

The manual shutdown switch pulled by a worker stopped gas from entering or leaving the station and vented natural gas out of the compressors. But the gas trapped in the building ignited and burned out in about 30 minutes while a second fire fed by the oil in the engine burned for two-and-a-half hours before it was put out by firefighters.

The compressor where the explosion originated "suffered severe damage" and is being replaced. A second compressor had wiring damage but was otherwise in "good working order."

The report also detailed new worker training and compressor lockout protocols and the steps Williams took over several days to restart the compressors safely.

It did not address why engines were turned on after DEP instructed the company not to. Williams has called it a "misunderstanding."

"We asked them to not resume running gas until we had a written report and an inspector out to the site," Connolly said. "We are not satisfied with the answer that Williams gave to DEP on when they restarted the compressor station."

The director of the Clean Air Council, an environmental group, also faulted Williams for restarting its engines without DEP permission and insisted that DEP complete its own investigation.

"Regardless of whether or not engines are functioning properly now," Joseph Otis Minott said, "this lack of concern for DEP's authority calls into question the company's attitude toward compliance with rules or orders designed to protect public health and safety."

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 14

Comment: Leak Repairs. For certain types of sources including centrifugal compressors and reciprocal compressors, pneumatic pumps, and storage vessel affected facilities, EPA is proposing that a leak or defect must be repaired as soon as practicable, but no later than 15 calendar days after it is detected. The first attempt at repairing the leak must occur within five calendar days of detection.

The DEP supports EPA's proposed requirement that a first attempt must be made by an owner or operator to repair the leak within five calendar days after the leak is detected; the repair of the leak should be completed no later than 15 calendar days after detection. However, the final LDAR provisions must ensure that any gaseous hydrocarbon leak including methane should be repaired within 15 calendar days of detection of the leak, if possible.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118. We note that the resurvey is the mechanism to ensure that the component has been properly fixed and that there are no longer fugitive emissions present.

Commenter Name: Roy Rusty Bennett
Commenter Affiliation: Mehoopany Creek Watershed
Document Control Number: EPA-HQ-OAR-2010-0505-6816
Comment Excerpt Number: 4

Comment: We recommend that repairs for sources of fugitive emissions are completed within 15 days and for those that may cause an immediate public health and safety risk – immediate repairs are necessary.

We recommend that sources of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions.

We recommend that 15 days is an appropriate amount of time for repair of sources of fugitive emissions at compressor stations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: J. Jared Snyder
Commenter Affiliation: New York State Department of Environmental Conservation.
Document Control Number: EPA-HQ-OAR-2010-0505-6894
Comment Excerpt Number: 9

Comment: EPA requested comment on whether a 15 day repair requirement is appropriate. The DEC agrees that a 15 day repair requirement is appropriate.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 54

Comment: EPA also requests comment as to its proposed 15-day repair timeframe. We support this timeframe as reasonable and in line with leading state requirements. Specifically, while the Colorado rule requires an initial attempt within five days, if a delay is warranted, operators must justify that delay and, when that justified reason ceases, operators then have 15 to make the repair. Pennsylvania allows operators of compressor stations and well sites 15 days to make repairs. Utah similarly requires the first attempt to repair a leak within five days of detection, but no later than 15 days after detection. Accordingly, EPA's 15-day repair timeframe is reasonable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 17

Comment: CONSOL believes that repair of the sources of fugitive emissions within 15 days of when they are found is acceptable, providing that EPA recognizes that repairs may need to be delayed due to operational or safety concerns and that EPA includes provisions for extension of this 15 day period in the proposed rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 12

Comment: EPA Must Provide Additional Time for Fugitive Emission Repairs that are Expected to Result in Excess Emissions

EPA solicits comment on whether fifteen days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. 80 Fed. Reg. at 56637. QEP believes that fifteen days from the date fugitive emissions are detected from a component is a reasonable amount of time to repair most leaks. However, QEP is aware of certain circumstances where repair within fifteen days of leak detection is unreasonable due to a potential increase in emissions resulting from the actual, immediate repair. For example, a fugitive emission component repair could require an operator to blowdown the leaking equipment which will produce more emissions from the blowdown than would result if the fugitive emissions were to continue until the operator has reason to shut in the well.

EPA's proposed 40 CFR § 60.5397a(j)(1) only provides an exception to the fifteen day repair requirement if "the repair or replacement is technically infeasible or unsafe to repair during operation of the unit...". 80 Fed. Reg. at 56668. In this exception, operators may complete the repair or replacement during the next scheduled shutdown or within six months. EPA does not specify whether unreasonable or significant excess emissions produced by an immediate repair is a "technically infeasible" or ((unsafe" reason to delay repair. QEP understands that excess emissions are a valid ((technically infeasible" reason to delay repair under the repair requirement exception in NSPS Subpart VV for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (40 CFR §60.4892-9(a)) and as relied upon by natural gas processing plants in NSPS Subpart KKK (40 CFR § 60.633(b)(3)(i)) and in NSPS Subpart OOOO (40 CFR § 60.5401(b)(3)(i)). See 40 CFR § 60.482-9(a) providing, "[d]elay of repair for equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown." QEP urges EPA to allow the same in NSPS OOOOa and to clarify such in the final rule. QEP recommends EPA revise § 60.5397a(j)(1) by adding the bold words to read:

(1) ... lf the repair or replacement is technically infeasible, unsafe to repair or will result in significant excess emissions during operation of the unit, the repair or replacement must be completed during the next schedule shutdown or within 6 months, whichever is earlier.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Jack Schwaller
Commenter Affiliation: HOERBIGER Corporation of America, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6799
Comment Excerpt Number: 9

Comment: If so, across the board 15 days to repair leak is too short: may be acceptable for small units, is too short for larger units

1. **Problems**
    1. Larger units take longer to replace the seal assemblies

        2. Add planning and sourcing (supplier deliveries increase with rod size)
        3. More involved designs are not supported with spare parts
    2. **Benefits to increase time**
        1. User will be able to fully troubleshoot problem.
        2. Insure original design is applied, not a second grade substitute.
        3. Can replace the Case Assembly or Rod if past retirement
        4. Can repair the case assembly or rod, can save $$.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 14

Comment: In the proposed regulation, EPA allows only 15 days to repair discovered fugitive emission leaks. We assert that this is not an adequate time frame to make repairs due to the disperse nature of operations and the need to allow for multiple attempts to repair.

Based on our experience managing LDAR programs, we recommend that EPA allow for multiple attempts to make the necessary repairs. There needs to be enough regulatory flexibility to address instances where several repair attempts are needed until the fugitive emissions leak is repaired. There are many instances, especially with tanks, where the exact cause of a fugitive emission leak may be uncertain and several attempts at a repair is necessary.

Solution: Anadarko strongly recommends that EPA allows for multiple attempts to make the necessary repairs after discovery of a fugitive emission leak.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Matthew D. Hall
Commenter Affiliation: Consumers Energy Company
Document Control Number: EPA-HQ-OAR-2010-0505-6862
Comment Excerpt Number: 4

Comment: Proposed Fugitive Emissions Program and Leak Detection and Repair Schedules:

Consumers Energy appreciates EPA's attempt to provide clearly defined thresholds for regulatory certainty; however, this proposal would significantly expand the scale and scope of costly leak detection and repair provisions far outside historic applications of regulatory authority. As EPA recognizes, multiple studies have shown that a majority of emissions come from a minority of leaks. EPA's proposed leak detection and repair program ignores this skewed distribution. The proposed rule would mandate an inefficient allocation of resources, because it would require addressing any source of fugitive emissions, at or above detection levels, regardless of the significance of the leak. In particular, the proposed 15 day repair schedule for detected leaks or equipment shut down in this application is entirely unreasonable, as it could result in a significant interruption of our ability to provide our customers with adequate natural gas during the home heating seasons. Safety is always Consumers Energy's over-arching objective. Flexibility in the prioritization and allocation of resources, including those needed to make repairs, is necessary to operate a safe and efficient system. EPA needs to propose a realistic repair schedule greater than 15 days to repair identified issues in the system.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118, for information on repair time. The EPA has defined the threshold at which fugitive emissions occur in the final rule. We do believe that it is necessary to fix any component that is above the threshold, even if the amount of fugitives is relatively small. Many small leaks added together can be larger than a single large leak. Additionally, if they are not addressed, small leaks can grow over time and become large leaks.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 24

Comment: The proposal fails to allow sufficient time for repairs

The proposed rule requires 15 calendar days for repair of any leaks detected, except where it is technically infeasible or unsafe during unit operations. The proposed rule notes this 15-day repair window is feasible, based on the industry's past experience in compliance. However, the proposed 15-day repair window with which industry has experience actually is based exclusively upon downstream facilities, not production facilities. This is not a sufficient basis for now finding feasibility: downstream facilities, such as gas processing plants or other large facilities, are manned 24 hours per day and 7 days a week. These downstream facilities generally have many spare components immediately available for repairs. A remote wellsite or unmanned compressor station is vastly different from a downstream facility, and as such, an operator of a wellsite requires additional time to conduct repairs.

More often than not, it is unfeasible for an operator to conduct repairs at the time of inspection. Additionally, replacement parts may not always be available. In instances where parts may be back-ordered, it is entirely conceivable that repairs could be delayed by 15 calendar days or more.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 15

Comment: Similar to the issue around flexibility for multiple attempts to repair, EPA needs to recognize other factors may affect the ability of a company to repair a fugitive emission leak within the specified duration. This will be a particularly significant issue if EPA does not allow for multiple attempts at repair over the appropriate duration. Repair of fugitive emission leaks can be delayed for locations due to weather, site proximity, need for custom parts and supplies, and logistical limitations. A 15-day repair requirements will not be feasible in every situation.

EPA has proposed language around a repair being technically infeasible. This language is unclear and impracticable. Repairs are technically infeasible based on the availability of necessary part(s), which are often custom, and difficulty of repair.

One of our key concerns is that EPA's Leak Detection and Repair, A Best Practices Guide (2007) states that a Drill and Tap ("D&T") procedure be required for components on a delay of repair ("DOR") list. EPA is relying on the utility and safety of this procedure based on its use in other industries, which is inappropriate. EPA should not dictate by regulation any type of procedure for repairing fugitive emission leaks especially for procedures that: (1) lack a well-developed industry standard for use; and (2) render questionable mechanical integrity of the equipment following it use. A D&T procedure is specialized and conducted on a limited basis by very few repair companies (less than three nationwide). Anadarko believes a D&T procedure is not a feasible repair methodology for this rulemaking for the following reasons: 1. A D&T procedure lacks established well-development industry standards or procedures. Rather the procedures for its use are limited to the opinions of the contractors using and promoting the procedure. To ensure appropriate use for safety and security purposes, a more broadly accepted industry standard is necessary. 2. Following application of a D&T procedure, the mechanical integrity of the equipment is no longer guaranteed. We have been directly informed by a contractor that they will not guarantee the mechanical integrity of equipment on which a D&T procedure is performed. This creates an unacceptable risk to the equipment, plant, and safety of employees, contractors and the public. 3. It is unclear whether EPA has consulted with OSHA and oil and natural gas industry experts to assess the safety of a D&T procedure at natural gas plants and other high-pressured facilities. EPA should engage in a comprehensive due diligence of a potentially dangerous process before taking the position that operators should perform a D&T procedure. 4. Valves are pressurized equipment that comply with ASME and/or API design codes (e.g. ASME B16.34, API-608 for ball valves). As part of piping specifications, valves are selected for specific process service and operational parameters rating. Valves have to meet code defined acceptance criteria prior placing in service. Tests such as visual surface examination, X-ray, hydro test and operational tests are required to ensure that their fabrication quality will satisfy the intended service conditions. 5. Repairs for code designed equipment shall follow ASME and/ or API recommended practices, defined as Recognized and Generally Accepted Good Engineering Practices ("RAGAGEP"). 6. Anadarko is committed to adhere to RAGAGEP, but in this case, we are not aware of any industry recognized standards and/or recommended practices that offers guidance regarding online valve leak sealing using D&T method and therefore are not comfortable executing the D&T methodology for in-service valve leak mitigation. Furthermore, we are not aware of any reference within the API-570 piping inspection and maintenance code that: 1) recommends D&T repair method; and/or 2) describes acceptance criteria for a performed repair to ensure that the integrity of the valve has not been compromised and can meet its intended design service conditions.

Solution: We recommend EPA allow DOR for reasons other than technically infeasible or unsafe to repair, such as, custom parts, part availability, and logistical delays. Additionally, we recommend that EPA retract its support of use of a D&T procedure as a criterion for the technically infeasible demonstration, until it has gained greater knowledge of and experience with a D&T procedure. We recommend that EPA form an industry work group including engineering and safety experts from oil and natural gas companies (the industry), OSHA, and other necessary stakeholders to ensure that use of a D&T procedure is appropriately executed, ensure equipment integrity and safety. Safety is Anadarko's number one priority. For an agency to ask a company to set safety aside in order to use a questionable leak repair technique is arbitrary and capricious.

Response: The EPA notes that neither the proposed nor final rule references the Best Practices Guide, and we have not specified its use. We believe the final rule adequately provides for and describes those situations where a delay of repair is allowable. We note that unavailability of supplies or custom parts is not a justification for delaying repair beyond the timeline in the final rule since the operator can plan for repair of fugitive emission components by having stock readily accessible or obtaining the parts within 30 days after finding the fugitive emissions. For more information see responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 13

Comment: EPA must also allow for more flexibility regarding the basis and reasons for delayed repair.

EPA places significant constraints on the basis and reasons for delayed repair, as well as the timing on when certain difficult to repair items must be repaired. Specifically, EPA's proposal allows for delay of repair when repair is technically infeasible or unsafe to repair during operation of the unit. EPA provides no discussion or definition of technically infeasible; however, Kinder Morgan believes that the terms used by EPA do not adequately capture all appropriate circumstances in which a delay of repair beyond fifteen (15) days may be justified. Constraints, part availability, and other considerations could represent a good cause for not meeting the 15-day repair timeline and operators should have some flexibility in completing the repair requirement.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 15.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 10

Comment: EPA Should Not Require All Repairs within 15 Days or Should Provide for a Delay of Repair Given Potential Disruptions of Service Associated with Its Proposal.

EPA proposes to require that an operator repair or replace the source of leak emissions as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. The proposed rule requires that leaks, no matter how small, must be repaired within 15 days. The Proposed Rule provides a delay-of-repair provision, at proposed 40 C.F.R. § 60.5397a(j)(1), that is much more limited than the leak detection and repair programs prescribed by other EPA regulations. Specifically, EPA's proposed delay of repair provision states:

"Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier."

Therefore, EPA would require an operator to repair all leaks within 15 days unless the repair is "technically infeasible or unsafe to repair during operation of the unit." If one of these two conditions were met, EPA would require the operator to make all repairs within six months. EPA's proposal, however, does not provide operators with adequate relief for other justified delays of repair.

As described more fully below, EPA should provide for a more expansive delay-of-repair provision consistent with INGAA's DI&M program, which is modeled after other existing EPA regulations and state programs. EPA also should delete the proposed six-month limitation on the delay-of-repair provision in its Final Rule.

EPA failed to explain why its leak repair requirements in its proposed rule do not provide for delay of repair consistent with its other programs.

In the Proposed Rule, EPA selected a 15-day repair period with insufficient delay-of-repair conditions for leak emissions. This is not consistent with the leak detection and repair programs prescribed by other EPA regulations such as Part 60, Subpart VV and Subpart VVa, "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006." In addition, EPA's proposed delay-of-repair provision for leak emissions is inconsistent with the delay-of-repair provisions proposed by EPA in this rulemaking for closed-vent systems and storage vessels.

Both Part 60, Subpart VV and VVa provide more reasonable criteria for delay of repair and more reasonable repair timelines. EPA has not explained why the delay-of-repair provision for identification and repair of methane emissions should be stricter than the provisions in other EPA regulations.

For example, Part 60, Subpart VVa at 40 C.F.R. § 60.482-9 provides that:

"Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit." 40 C.F.R. § 60.482-9(a);

Delay of repair for valves will be allowed if "The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair." 40 C.F.R. § 60.482-9 (c)(1); and

"Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown." 40 C.F.R. § 60.482-9 (e).

Part 60, Subpart VV provides identical delay of repair provisions.

Therefore, unlike the delay-of-repair provision in this Proposed Rule, these other Part 60 provisions permit an operator to:

Delay a repair beyond six months if the repair requires a shutdown and the next shutdown period will occur in more than six months (rather than a maximum delay of six months);

Delay a repair if the operator demonstrates that purged (i.e., blowdown) emissions resulting from immediate repair exceed the fugitive emissions likely to result from the delay; and

Delay a repair beyond the next shutdown if there are issues associated with the availability of valves or valve assemblies.

In addition, EPA does not explain why its delay-of-repair provision for fugitive emissions at a compressor station is more stringent than the proposed delay-of-repair provisions for the treatment of closed-vent systems. In proposed 40 C.F.R. § 60.5416a(b)(10), EPA provides that:

Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

Further, state regulatory programs also provide more reasonable criteria for delay of repair. For example, Colorado's LDAR rule for oil and gas operations includes delay-of -repair provisions. The Colorado rule provides that:

If parts are unavailable, the operator must order parts promptly and complete repair within 15 working days of parts receipt (or the next shutdown after the part is received if repair requires shutdown); and

If delay is attributable to other good cause, complete repair within 15 working days after the cause of delay ceases to exist.

The Colorado regulation does not provide an explicitly defined or list of "good cause" criteria. Yet, "good cause" delay could include, based on practical experience, the need for a specialized technical skillset to complete the repair when scheduling requires more than 15 days, warranty issues that require more than 15 days to address parts replacement, and safety or accessibility issues that warrant waiting for a shutdown based on operator judgment.

The delay-of-repair provision in INGAA's DI&M program is modeled after delay-of-repair provisions in Part 60, Subpart VV and Subpart VVa and Colorado's regulatory program. Therefore, INGAA advocates that EPA revise proposed 40 C.F.R. § 60.539a(j)(1) to adopt the following delay-of-repair provisions from INGAA's DI&M program:

EPA should permit an operator to delay repairs beyond the 15-day deadline, if an operator can satisfy and document one of the following conditions:

1. Repair Requires Unit /Station Shutdown – If the repair of any component is technically infeasible without a process unit shut down or if the source cannot be repaired during operation of the source.

2. Equipment Isolated From Process – If the repair is unnecessary because the equipment is isolated from the process (i.e., the component/equipment is taken out of gas service, and repair is completed before a return to service).

3. Valves Where Purged Gas Would Exceed Leaking Gas – If immediate repair of the equipment would result in vented emissions (from equipment purge) greater than the emissions resulting from delay.

4. Valves Where Leakage Would Be Controlled – If leaked gas is collected and destroyed, recovered in a control device, or used for some other beneficial purpose.

5. Repair Is Unsafe, Inaccessible, or Difficult to Monitor – If a repair cannot be made due to safety issues.

6. Equipment Must Be Ordered for Repair – If additional time is needed to procure equipment or components necessary to complete the repair, the repair timing will be based on equipment delivery dates that may depend upon manufacturer stock and shipment schedules.

7. Specialized Skill Set Must Be Scheduled – If the repair requires a specialized technical skillset, the repair timing will be based on personnel scheduling.

EPA has not explained why this proposed rule requires a 15-day leak repair period with a limited six-month delay of repair condition only when the repair "technically infeasible or unsafe to repair during operation of the unit," when its other regulatory programs permit delay of repair in other, more numerous circumstances. INGAA believes that this provision is arbitrary and should be modified, as described above.

At a minimum, EPA should revise proposed 40 C.F.R. § 60.5397a (j)(1) to adopt the same delay-of-repair provisions in Part 60, Subpart VVa or, if not, explain its departure.

In all cases, the operator would address repairs as soon as practical. For example:

If a repair requires a shutdown or if a repair is delayed due to emissions from purged gas exceeding the emissions that result from the leak, the operator would complete the repair the next time the unit or process is shut down and/or purged;

For parts such as large valves with extended delivery times, the operator would complete the repair within 15 days of delivery or upon the next shutdown after delivery if a unit or process shutdown is required to complete the repair; and

For repairs that require a specialized skill set, the operator would complete the repair planning within 15 days, and schedule and complete the repair as soon as feasible.

The 15-day repair requirement is unreasonable since most compressor station replacement parts are not available in 15 days.

EPA's proposal to require repairs within 15 days, without reasonable delay-of-repair provisions, is unworkable. T&S pipeline companies operate dozens of different models of reciprocating and centrifugal compressors with different vintages and manufactured by different vendors. Availability of replacement parts could be challenging especially for existing facilities that become subject to EPA's proposed modification provisions. Each compressor station, regardless of vintage, type or model, has thousands of components and equipment parts. Operators do not warehouse all of the many replacement component parts – including a variety of valves, flanges and the many other components listed in the Proposed Rule. It is impractical to maintain such a large spare parts inventory. Due to the wide variety of compression equipment and compressor station piping, manufacturers do not stock all possible replacement equipment. Other than the most essential parts, ordering and obtaining those replacement parts from the manufacturer or other vendor becomes the critical path for completing repairs. This usually takes significantly longer than 15 days. Thus, delay of repair due to parts availability and delivery schedule is reasonable, and is a common delay of repair provisions in EPA and state LDAR programs.

Especially for existing compressor stations that trigger "modification," there often are waiting periods because replacement parts for older compressors cannot be acquired "off the shelf" and in many cases must be specifically manufactured on a special-order basis. For example, to replace a component, such as a crank shaft, on a vintage reciprocating compressor would require the component to be removed from service and shipped to the manufacturer. The manufacturer then would make a mold of the component and re-cast a new piece. The process to remove, ship and re-cast a new component may take six months or longer. For additional examples, see Appendix D.

Moreover, EPA's six-month extension – for repairs that require a pipeline operator to shut down a compressor station – does not apply to an operator that cannot receive replacement parts within 15 days. Even if EPA had proposed to include the unavailability of parts in its six-month extension, the six-month time period would be insufficient in all cases. The repair of an individual compressor unit or its associated piping components may limit the capacity of the compressor station even if the entire station does not shut down. Compressor stations normally have multiple compressor units. An individual compressor unit and its associated piping can be shut down to conduct a repair while the other compressor units at the station remain in operation. However, if the leak repair is within the overall compressor station piping, then a shutdown of the entire compressor station would be required. Both of these repair scenarios could potentially impact customer deliveries if EPA imposes a six-month time limit rather than relying on the next unit, process or station shutdown – whichever is necessary to complete a particular repair.

Further, if all operators must adhere to the 15-day repair schedule, the interstate pipeline industry may not have a sufficient work force to comply with this timeline. Personnel capable of working on compressors and compressor station piping must meet the Pipeline and Hazardous Materials Safety Administration's (PHMSA) operator qualification requirements. While companies currently have sufficient qualified personnel to conduct normal operations and repairs, the proposed Subpart OOOOa leak detection and repair requirements may significantly increase the number of qualified operators and maintenance personnel required to conduct leak surveys and repairs. Furthermore, the pipeline industry will be competing for qualified personnel to make necessary repairs at the same time it is implementing pipeline safety integrity management work pursuant to current and likely more rigorous upcoming regulations under the Pipeline Safety Act. The pipeline industry also is competing for personnel with the rest of the natural gas value chain – producers and local gas utilities – to comply with EPA's regulations and with the oil pipeline industry, which is performing its own pipeline safety work.

Therefore, EPA should modify its proposed rule to provide delay-of-repair provisions, as discussed above, consistent with INGAA's DI&M program.

EPA failed to consider the adverse effects of the proposed rule. EPA failed to consider the 15-day repair requirement's environmental and operational consequences, including the emissions that would occur to repair a leak and the service disruptions to customers while a piece of equipment is out of service for repair.

a. The proposed rule's 15-day repair requirement would result in unnecessary blowdowns and methane emissions releases.

EPA's proposal to require an operator to repair leaks within 15 days is unreasonable because, in many cases, it would necessitate releases of methane larger than what would have occurred without the rule. EPA's 15-day repair requirement will require operators, in many situations, to conduct a blowdown to vacate gas from the equipment or station piping before repairing or replacing leaking equipment or component(s) at a compressor station. One way to explain blowdowns is to use the water pipe inside a home as an example. A blowdown event at a pipeline connected to a compressor station would be similar to closing the main water valve to a home and then opening a faucet to allow all of the water to drain from the pipe before repairing a broken or cracked water pipe.

The amount of gas blowdown will vary, but, in many cases, it could be much greater than the methane emissions that would result from delaying the leak repair. If a significant blowdown event were required to complete a repair, it may be more environmentally beneficial to complete the repair at the next scheduled shutdown. EPA should allow operators flexibility to make reasonable judgments on whether to delay repair of a leak to minimize methane emissions.

For example, a leak can occur in a compressor unit's piping (valves, flanges, etc.) that would require the compressor unit to be shut down and the associated piping (from upstream isolation valve to downstream isolation valve) to be blown down resulting in greater emissions than what would be emitted by the leaking components if the repair were delayed. Furthermore, if the leaking component(s) were part of the overall compressor station piping, then the entire contents of the compressor station piping would need to be blown down to conduct the repair. Once again, greater emissions would result from the blowdown than what was being leaked.

If an operator could delay the leak repair, it would have a greater opportunity to minimize, or possibly eliminate, the amount of additional methane gas it would need to blowdown. Typically, this would result in an operator completing the repair the next time the unit or process is blown down for other operational reasons. For example, an operator could make repairs during a month or season that the compressor is not operating due to lower flow volumes on the pipeline. Another option could be for a pipeline customer to draw down gas from the pipeline slowly to reduce the volume of gas in the pipe at or near the compressor or for the customer to move the gas into storage. However, these options are case specific and each situation would need to be evaluated for feasibility. A 15-day repair deadline would not provide the operator with the flexibility to work with its customers (often referred to as shippers) to minimize releases. INGAA also notes that the re-routing of methane gas is not always possible to avoid blowdown because many older compressor stations and their pipelines are not designed to re-route natural gas.

In addition, not all leaks are significant, particularly if the leaks release de minimis amounts of methane to the atmosphere. In fact, EPA recognizes that some level of methane release is acceptable to accommodate necessary equipment operations. It is well reasoned for an operator to delay repairing a de minimis leak if the volume of methane emitted in the process of repairing the leak exceeds the methane emissions likely to result from the delay. EPA should allow operators the discretion to decide whether more methane emissions would result from conducting a blowdown in order to make a repair within 15 days (versus the volume of methane emitted should the leak not be repaired). In such cases, operators would continue to monitor a leak and the need to make repairs, and most commonly repair the leak when the unit or process is next blown down for other operational purposes.

Specifically, EPA should revise its proposal to permit an operator to delay a repair if it demonstrates that emissions resulting from the immediate repair (e.g., blowdown) exceed the fugitive emissions likely from the delay. The repair would be scheduled to be completed during the next unit, process or station shutdown, depending on what level of shutdown and blow down is needed to address the repair.

b. The proposed rule could result in service disruptions to pipeline customers.

There is no question that a pipeline operator may need to shut down an entire compressor station or a compressor unit to perform larger repairs. If, for example, a pipeline operator must replace a valve that is used to isolate the compressor station from the mainline, it typically would take the compressor station out of service for six days once the pipeline had obtained the replacement part(s) from the manufacturer/vendor. By contrast, if a pipeline operator must replace a smaller, eight-inch valve connected only to a compressor unit, the pipeline operator would need to take the compressor station out of service for three to four days. These estimates, however, assume that all compressor station equipment parts are readily available from the manufacturer and can be timely shipped to the location, which, as discussed above, may not be the case. The compressor station would be out of service for the full timeframe required to order and obtain the part(s) and to conduct the repair or replacement, or risk being out of compliance with Subpart OOOOa in order to continue operations to meet critical demand. In many cases, this total timeframe could significantly exceed 15 days.

During the time the compressor station is out of service, the pipeline will need to reduce maximum capacity on it system. Depending on its customers' demand for gas, a pipeline operator may need to restrict transportation service through affected segments of its system while the compressor station is out of service.

If a pipeline identifies a leak in January, during peak natural gas usage, and must make repairs within 15 days, then, under EPA's proposed rule, that pipeline operator would risk service disruptions and thereby impair reliability in order to repair even the most de minimis leaks. A similar case could occur during high cooling day demand periods when electric generators use natural gas as a fuel. The arbitrary 15-day repair requirement limits the ability of the pipeline operator to make important operational decisions to maintain the delivery of natural gas to its customers.

Moreover, a transportation reduction on one pipeline could affect other pipelines in the transportation delivery path. Natural gas is often transported across several pipelines, from a producing region to the ultimate customers. If one pipeline in the path is experiencing service disruptions due to the inability to plan and prioritize repairs, there could be service disruptions affecting larger areas and more gas customers along the entire gas delivery chain. It is possible that these larger service disruptions could affect industrial customers, including factories that have two or three manufacturing processes or continuous manufacturing over a 24-hour basis (such as chemical and refining industries). Additionally, some service disruptions might affect electric power generation, which will, under the Clean Power Plan (CPP) and separate state regulations, increasingly be using natural gas over coal-fired generation from 2016-2030. Hospitals, data management centers and other industrial manufacturing customers require reliable natural gas delivery through the interstate pipeline industry just as the electric power sector will require reliable natural gas delivery.

EPA's failure to acknowledge likely service disruptions caused by its 15-day repair requirement, without adequate delay-of-repair provisions as described above, is not reasoned decision making and fails to recognize the true costs of this rule.

In establishing the Best System of Emission Reductions (BSER) under the CAA, EPA can take into account non-air and energy issues and other factors. There are obvious and important implications on energy infrastructure and availability that EPA has not considered. INGAA believes that EPA should consider the feasibility, cost-effectiveness, non-air issues, and other issues when considering delay-of-repair provisions that should be included in the rule.

Response: In the final rule, owners and operators must repair fugitive emission components within 30 days of finding fugitive emissions. We have also modified the delay of repair provisions to allow components that cannot be repaired without a shut-in, shutdown or blowdown to be placed on delay of repair until the next shut-in, shutdown or blowdown or within 2 years of finding the leaking components. See responses to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 15, and DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35. Also see sections VI.F.1.e and VI.F.2.e of the preamble to the final rule for further discussion.

Commenter Name: C. Wyman; Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association; American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6874; EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 4; 6

Comment: <u>EPA's proposed LDAR repair schedule should take into account real world operations and incorporate "delay of repair" provisions</u>.

EPA's proposed LDAR program to address fugitive emissions from compressor stations would require that an identified source of fugitive emissions be repaired or replaced in a specified amount of time. EPA's proposed repair schedule fails to take into account the logistics of real-world operations, is unnecessarily burdensome, and is more stringent than LDAR in other NSPS. In fact, in some cases, EPA's proposed repair schedule would result in emissions in excess of the fugitive emissions the repair/replacement is intended to address. AGA urges EPA to address these concerns by incorporating "delay of repair" provisions into the LDAR program for fugitive emissions from compressor stations.

Under the proposed rule, EPA would require leak surveys using OGI technology. In some circumstances, OGI can identify very small quantities of fugitive emissions. Because EPA's proposal does not define a leak concentration associated with OGI technology, all detected leaks must be addressed. Once a leak has been identified, EPA's proposed LDAR would require that an identified source of emissions be repaired or replaced either (1) no later than 15 calendar days after detection of fugitive emissions or (2) where repair is technically infeasible or unsafe during unit operations, the earlier of six months or the next scheduled shutdown.

AGA appreciates EPA's recognition that not all repairs/replacements can occur while a unit is operating. However, EPA's proposal does not provide facilities with a repair/replacement schedule that takes into account when and how a unit is shut down. As an initial matter, EPA's proposal fails to recognize that in the situation where a repair/replacement requires that a unit be shut down, the next shutdown may be scheduled in the coming 15 days. In this situation, in order to comply with the provisions, the fugitive emissions source would need to be repaired/replaced during that scheduled shutdown, despite the fact that may not be enough lead time to schedule or obtain necessary parts to undertake the repair/replacement.

A broader concern with EPA's proposed LDAR repair schedule is that it would not necessarily align with a company's scheduled maintenance shut downs for a compressor station. The company may not have a shutdown scheduled to occur for the affected compressor station within 6 months from leak detection. In this situation, the compressor station may need to be shut down out of schedule for the sole purpose of repairing/replacing the source of a leak. Often times a shutdown is accompanied by a blow down, a process that can result in emissions in addition to those fugitive emissions being addressed. And, because the fugitive emissions being addressed may be a rather insignificant source of emissions on account of the proposed rule not containing a leak concentration definition, the emissions associated with the extra, unscheduled blowdown and shutdown will often result in more emissions than the original leak.

In addition, irrespective of whether the repair/replacement can be accomplished during operation, the proposed LDAR repair schedule does not account for delays in repair/replacement that could be associated with acquiring difficult to obtain parts such as large isolation valves. In this situation, the proposed rule would require facilities to remain idle while waiting for delivery, resulting in unforeseeable costs and emissions that are difficult to forecast.

The inability of a facility to take operations into account when scheduling a repair also could have broader system-wide repercussions such as requiring a facility to shut down during critical times of high demand, which could cause gas deliverability and other reliability concerns.

To remedy these concerns, AGA urges EPA to incorporate "delay of repair" provisions that consider operational and scheduling constraints into its proposed LDAR for fugitive emissions from compressor stations. "Delay of repair" provisions are common in LDAR found in other NSPS (and NESHAPs), and are included in EPA's proposed standards for compressors, pumps, and storage vessels. The other NSPS and NESHAPs address VOCs and hazardous air pollutants (HAPs), pollutants of greater short-run concern than methane. Yet by including "delay of repair" provisions EPA has afforded sources subject to those regulations more flexibility than the Agency proposes to offer through its proposed LDAR. EPA has not explained why the "Best System of Emission Reduction" (BSER) for a GHG program is more stringent than comparable previous LDAR programs for VOCs in other NSPS rules.

AGA believes that the proposed LDAR for fugitive emissions from compressor stations should be revised to include additional delay of repair provisions. Examples from other regulations, such as Part 60, Subpart VV and Subpart VVa include:

- No limit applies to the period until scheduled shutdown (the proposed rule limits the duration to 6 months maximum for leaks that require shutdown to repair).
- Repair can be delayed if the operator demonstrates that purged (i.e., blowdown) emissions resulting from repair exceed the fugitive emissions likely to result from the delay.
- Repair can be delayed beyond the next shutdown if there are issues associated with the availability of valves/valve assemblies.

Other example delay of repair criteria include:

- If parts are unavailable, order promptly and complete repair within 15 working days of receipt of parts, or the next shutdown after the part is received if repair requires shutdown.
- If delay is attributable to other good cause, complete repair within 15 working days after the cause of delay ceases to exist.

The last two examples are based, in part, on delay of repair provisions in Colorado's LDAR rule for oil and gas operations. For the latter item, examples of "good cause" could include the availability of a specialized technical skillset to complete the repair, warranty issues that require more than 15 days, or safety or accessibility issues.

EPA has not provided a justification for imposing such stringent repair schedules on addressing fugitive emissions from compressor stations, especially in light of the fact that more flexible schedules are provided for addressing emissions generally associated with more stringent regulation and that EPA's proposed schedule actually could result in an environmental dis-benefit of increased emissions. For these reasons, AGA encourages EPA to incorporate the "delay of repair" provisions consistent with the list above, including the ability for the operator to demonstrate good cause for delaying a repair.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 15 and DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 20.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 17

Comment: Comments on EPA's Proposed LDAR Monitoring Standards

EPA Must Provide Increased Flexibility for the Repair of Fugitive Emissions Leaks

GPA requests that the EPA provide increased flexibility to affected facilities that detect fugitive emissions leaks during required monitoring activities. As proposed, EPA would only provide affected facilities with 15 days to make necessary repairs, with a few limited exceptions that provide up to 60 days. See Proposed 40 C.F.R. § 60.5397a(j)(1). These deadlines are wholly inadequate given the unique challenges faced by owners and operators of well sites and compressors stations. Thus, GPA urges EPA to provide increased time for owners and operators to repair fugitive emissions leaks after detection.

First, GPA urges EPA to extend the primary deadline for repairs from 15 to 60 days. The 15-day deadline is used by EPA in Subparts VV, VVa, KKK, and OOOO for natural gas processing plants and other large facilities in the SOCMI sector, which are continuously manned facilities with dedicated operational and/or maintenance staff. In addition, those facilities frequently keep replacement parts on site due to high component counts. In contrast to processing plants, well sites and compressor stations are often unmanned facilities located in remote areas where on-site storage of parts is not feasible or cost effective and it would be difficult to secure and transport parts in a timely manner. In addition, for facilities with older equipment, replacement parts may not be available for purchase. In those cases, an operator would be required to obtain a custom-manufactured part to replace a leaking component, further extending the time needed for repairs. When custom-manufactured parts are required, EPA should allow a delay of repair until the new part can be made available for installation.

Access to these sites can also be limited by inclement weather, including snowfall and flooding. In addition, GPA anticipates that many operators will contract for both OGI monitoring and repair services at well sites, and compressor stations, meaning that repairs may be delayed due to contractor availability. Thus, while GPA's members are committed to repairing fugitive emissions leaks as soon as practicable, 15 days is simply too short a deadline for compressor station sites and well sites. Increasing the repair deadline in 40 C.F.R. § 60.5397a(j)(1) to 60 days will provide owners and operators with the necessary time to coordinate repair services at such remote locations. In addition, EPA should clarify that a component should be deemed repaired if subsequent monitoring under Method 21 or OGI indicates that the component is no longer leaking.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118. The EPA agrees that the component is repaired if the resurvey indicates that there are no fugitive emissions, i.e., nothing is visualized with OGI or the Method 21 reading is less than 500 ppm above background.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 20

Comment: Comments on EPA's Proposed LDAR Monitoring Standards D. EPA Must Provide Increased Flexibility for the Repair of Fugitive Emissions Leaks

Fourth, GPA urges EPA to expand and clarify the types of activities that can justify an extension beyond the otherwise applicable repair deadline. Due to the remote nature of many well sites and compressors stations, inclement weather, availability of parts, and available of repair crews can all delay equipment repairs. GPA requests that EPA specifically lists these exceptions in the text of 40 C.F.R. § 60.5397a(j)(1). Specifically, GPA requests that EPA address the availability of parts in the same manner as in NSPS Subpart VVa. See 40 C.F.R. § 482-9a(e) (allowing delay of repairs until a second shut-down event when parts are unavailable). In addition, affected facilities should be able to delay repair if they can demonstrate that the emissions of purged material resulting from immediate repair is greater than the fugitive emissions likely to result from delay of repair. Again, EPA has already addressed this issue in NSPS Subpart VVa and in Proposed 40 C.F.R. § 60.5416a(b)(10) and could include the same provision in 40 C.F.R. § 60.5397a(j)(1).

Fifth, GPA urges EPA to provide additional flexibility to owners and operators of affected facilities by allowing them to respond to fugitive emissions leaks by isolating the equipment and taking it out of VOC/methane service. Such an approach will effectively stop the fugitive emissions until a repair is made. EPA has included such a provision in NSPS Subpart VVa and GPA requests that EPA include a similar provision here. See 40 C.F.R. § 60.482.9a(b) ("Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.").

Sixth, GPA urges EPA to eliminate the secondary six-month deadline for repairs in the event that an extension is appropriate. Such a deadline is arbitrary and is inconsistent with the way that well sites and compressor stations are operated. Instead, the time allowed for repair should be extended until the next scheduled shutdown. This proposed requirement is more stringent than the delay of repair requirements for gas processing plants in 40 C.F.R. § 60.482a-9.

Response: We disagree that inclement weather, the availability of parts or crews constitute a delay of repair. The final rule allows owners and operators 30 days to repair components that are found to be sources of fugitive emissions. Similar to the provisions of §60.482a-9, we have finalized a delay of repair provision for components that cannot be repaired within 30 days of finding fugitive emissions if a greater environmental impact would result (i.e. blowdown event) from making such a repair. An owner or operator can isolate the fugitive emission component from the well site production or compressor station, to stop the fugitive emissions, if repairing such a component would result in a well shutdown, shut-in, blowdown or compressor station shutdown. However, the component would need to be repaired after the next shutdown, shut-in or blowdown or within two years of finding fugitive emissions, whichever is earlier. See section VI.F.1.e and VI.F.2.e of the preamble to the final rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 131

Comment: Forcing All Repairs Within 6 Months Is Unreasonable Due To True Cost Impacts.

A minority of detected leaks require more time to be repaired because they require a full shutdown of the well in order to do the repair. For example, recent data from Colorado's Reg 7 indicate that about 5% of identified leaks required a delay of repair. Repairs on the well head itself require full shutdown of the well. Some repairs require a workover of the well. Also, many companies do not allow hot work to be performed on the well site due the risk of explosion or fire. The well must be shut in and the equipment purged in order to do any hot work such as welding for repairs. Many different issues must be assessed before a well is shut in and equipment purged for repairs. Shutting down the well could result in losing the well completely or damage to the formation that can reduce production. The emissions from shutting in the well and purging the equipment could result in more emissions than are being released from the leak. Also, EPA did not consider the cost of lost production during repairs in the cost analysis for fugitive leaks which can be significant.

Some repairs at compressor stations require the compressor station to be shut in which could require shutting in all the wells that feed into the compressor station as well. Most compressor stations in the gather system do not have a way to by-pass the compressor or parts of the system so work can be done. Bringing down the compressor station could result in shutting in parts of a field and losing the production from that portion of the field which is a huge cost. Lost production from compressor shutdowns was not included in EPA's cost estimate.

The unreasonableness of the requirement to repair a leak within 6 months is even more apparent when applied to integrated production arrangements such as those on the North Slope of Alaska. Fields on the North Slope are arranged with multi-well pads feeding into a small number of centralized production stations where primary separation and some pre-treating and compression of gas occurs. Gas from these central production stations is routed to a gas processing facility, oil to the Trans-Alaska Pipeline, and produced water to reinjection. Dependent on where a leak occurs in this integrated production arrangement repairing a leak within 6 months may necessitate shutting down an entire section of a field feeding a particular central production station or perhaps a series of central production stations. Given the geographic and seasonal realities of the Alaskan North Slope, oil and gas operators schedule large separation facilities shutdowns during the summer months. With the litany of plausible scenarios that could result in a separation facility being required to shut down in order to fix a leak in late fall, winter, and early spring, such shutdowns will result in greater safety and integrity concerns. In addition, the flaring of between 250,000 MMscf and 500,000 MMscf of gas during shutdowns may be an unintended and unavoidable consequence of the proposed rule. Simply stated, the emissions release associated with shutting down a production facility; shutting in and freeze protecting wells; and depressuring and purging the necessary equipment will result in far greater emissions than are being released from the leak that could be repaired during the next scheduled process shutdown. In addition to the increased safety concerns and counter-productive flaring, implementing the repair requirements as currently drafted will also result in severe economic repercussions. Every day of a non-scheduled or non-summer shutdown will result in millions of dollars in lost revenue for the State of Alaska and the operators. Dependent on the length and extent of the shutdown required and difficulty restarting the wells and facilities, taking such an action may impact the domestic US supply of crude oil, particularly in the West Coast markets where most Alaska crude is shipped. It is clear that EPA did not contemplate such potential wide ranging and large impacts when considering the requirement for repair of a leak within 6 months. Although the North Slope is an extreme example due to the unique climate realities, similar impacts would occur on a smaller scale for other integrated production arrangements.

EPA should allow for delay of repair of fugitive components until the next shutdown. EPA has allowed for delay of repairs beyond 6 months for reasons other than technical feasibility and safety, such as availability of supplies, availability of custom parts and where shutdown emissions are larger than what would be reduced. Subpart §OOOOa should be less stringent than what is required under VVa. VVa under 60.482-9a allows for the following delay of repairs and NSPS OOOOa should allow for equivalent delay of repair.

API was unable to gather and provide the typical times between shutdowns of well sites and compressor stations due to the short comment period on this rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8 and DCN EPA-HQ-OAR-2010-0505-6881, Excerpt 20.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 25

Comment: AGA Urges EPA To Consider Revisions That Promote Consistency With Other EPA Programs.

AGA appreciates EPA's attempt to minimize the burden on regulated parties by seeking comment on how the Agency can avoid duplication or conflicts with other existing regulations. Several examples are discussed in these comments (e.g., delay of repair provisions), and reiterated below.

Delay of repair provisions should be incorporated in EPA's LDAR program for fugitive emissions from compressor stations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 12

Comment: Finally, for repair of leaks, EPA is requiring that fugitive emissions be repaired or replaced as soon as practicable but no later than 15 days after detection. If the repair is technically infeasible or unsafe to repair during operation of the unit, the repair must be completed during the next scheduled shutdown or within 6 months, whichever is earlier. WBI Energy recommends excluding the 6 month requirement for transmission and storage compressor stations. These facilities conduct scheduled maintenance at a time that is least disruptive to the overall pipeline system. The rule should allow companies to repair fugitive emissions during the next scheduled facility maintenance shutdown.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 10

Comment: The proposal requires that repair of leaking components be completed within 15 days of discovering a leak unless it is deemed technically infeasible. EPA has cited similar requirements in other industries as justification for the appropriateness of this response time for completing repairs. The specific challenges of the natural gas industry, which has hundreds of compressor stations along the pipeline, are different from other industries, such as oil refining, where the number of affected facilities is significantly lower. In addition, there are contractual obligations regarding system reliability (availability) with customers that make it difficult to take compressors or portions of the facility offline without significant financial penalties. In addition to financial penalties, there are substantial concerns with not meeting demand which could result in critical customers (i.e., hospitals, schools, nursing homes, residences, etc.) being without gas in during extreme weather conditions. In the proposal, EPA offers that if the repairs cannot be completed within the 15 calendar days, the components can be placed in delay of repair not to exceed six months. Some repairs require the ordering of specialized parts or trained personnel, which delay repairs beyond the company's control. Some large diameter valves, for example, take longer than six months to receive. More importantly, there is no acknowledgment in the proposal to allow for delay of repairs if the gas loss associated with blowing down the equipment exceeds the gas loss from the leak(s). EPA should provide additional "Delay of Repair" options in its final rule. Dominion supports the recommendations provided by the Interstate Natural Gas Association of America (INGAA) in their comments submitted in this docket. In some cases, it is difficult to anticipate if the repairs can be completed in six months and additional time might be warranted before the compressors can be taken offline to fix the leaks. Some of Dominion's compressor stations may not schedule a downtime for a year or more due to market conditions. We urge EPA to consider these constraints and revise the repair requirement to allow repairs to be delayed until the next time when the compressors can be taken offline (even if this results in extensions beyond six months).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 15.

Commenter Name: Kelly Guertin, Senior Environmental Engineer, Environmental Management and Resources
Commenter Affiliation: DTE Energy (DTE Gas Company)
Document Control Number: EPA-HQ-OAR-2010-0505-7052
Comment Excerpt Number: 8

Comment: DTE Energy agrees with INGAA that EPA should not require all repairs within 15 days or should provide for a delay of repair given potential disruptions of service associated with its proposal. As described further in comments submitted by INGAA EPA should provide for a more expansive delay of repair provision consistent with INGAA's DI&M program and EPA should delete the proposed six-month limitation on the delay or repair provision in its Final Rule.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 18

Comment: §60.5416 Repair of Leaks in Covers or Closed Vent Systems: The repair of a leak or defect "as soon as practicable" is sufficient to cover immediate or first attempts at repairs. Apache agrees that any leaks that are discovered during routine inspections should be repaired quickly. We anticipate as many leaks as possible would be repaired by the wellsite operator or work crew prior to leaving the site. Additionally, Apache believes that Section (c)(4)(i) requiring repair attempts "no later than 5 calendar days after the leak is detected" is - at best - made redundant by the language in (c)(4) stating the leak should be repaired "as soon as practicable" and should be removed. At worst, the two provisions are contradictory.

Response: The EPA disagrees that the two provisions cited by the commenter are contradictory. Paragraph 60.5416a(c)(4) introduces as soon as practicable. The subparagraphs place limits on "as soon as practicable." Without the 5-day limit in §60.5416a(c)(4)(i), the "practicable" timeframe could extend indefinitely.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 13

Comment: EPA Must Provide Operators with Adequate Time to Repair/Replace and Resurvey Fugitive Emissions

Proposed 40 CFR Section 60.5397a(j)(2) requires operators to resurvey each repaired or replaced fugitive emission component ((as soon as practicable, but no later than 15 days of finding such fugitive emissions, to ensure there is no leak." 80 Fed . Reg. at 56668. QEP reads EPA's proposed regulatory language to require resurvey within fifteen days from the date the fugitive emissions at issue were detected, regardless of when the repair or replacement takes place. However, in several instances in the preamble to NSPS OOOOa, EPA indicates that the fifteen day timeframe to resurvey a repair or replacement commences from the date the repair or replacement took place- not the date fugitive emissions were first detected. See 80 Fed. Reg. at 56612 providing, "[a]ll sources of fugitive emissions that are repaired must be resurveyed within 15 days of repair completion to ensure the repair has been successful...". QEP agrees with EPA's sentiment here.

We urge EPA to revise the regulatory language in NSPS OOOOa and clarify in the final rule preamble that resurvey is required within fifteen days from the date the repair or replacement takes place. Ultimately, EPA's fugitive emission control program is about identifying, effectively addressing, and preventing equipment leaks. EPA must give operators sufficient time to make any necessary repairs or part replacements. QEP agrees that fifteen days is reasonable for this task in most instances.

However, QEP submits that fifteen days is unreasonable for the tasks of repairing or replacing components and resurveying the repair/replacement. To ensure a successful fugitive emission control program, QEP urges EPA to provide operators with an additional fifteen days from the date of repair or replacement to resurvey by revising §§ 60.5397a(j)(2) and 60.5397a(j)(2)(i) by adding the bold words to read:

(2) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 15 days **following repair or replacement**, to ensure that there is no leak.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initial found, the operator may resurvey the repaired fugitive emissions components using either Method 21 or optical gas imaging within 15 days **following repair or replacement**.

Response: The EPA has revised the regulatory text in §60.5397a to indicate that the resurvey must take place within 30 days of repairing or replacing the component. See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118, for information on repair times.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 20

Comment: EPA Has Not Acknowledged or Taken into Consideration Existing PHMSA Regulations for the Timing of Leak Repairs.

In the preamble, EPA frequently refers to the need to leverage existing programs. However, EPA does not indicate in the Proposed Rule that the agency has conducted any review, comparison, or reconciliation with other regulatory programs. In particular, EPA does not recognize the existing regulations that cover leak repairs. PHMSA has the authority to regulate leak detection and repair for natural gas pipelines and facilities and exercises that authority through its existing regulations.

Specifically, PHMSA requires operators to conduct leakage surveys, patrol rights-of-way, repair hazardous leaks promptly, and report unintentional estimated gas loss of three million cubic feet or more. PHMSA requires that operators repair all "hazardous" leaks promptly. Pipeline and facility operators must also report to PHMSA the number, location, and cause of all leaks eliminated or repaired annually. PHMSA defines a leak in the annual reporting forms as "…unintentional escapes of gas from the pipeline that are not reportable as Incidents under § 191.3. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak. Operators should report the number of leaks repaired based on the best data they have available."

Rather than issuing its own leak repair regulations requiring operators to repair all leaks within 15 days, EPA should work with PHMSA to support the existing regulations. As illustrated above, PHMSA recognizes that not all leaks are the same and operators need to acquire replacement parts and consider disruptions in service. EPA should consult with PHMSA and rely on the time frames for leak repairs set out in existing federal regulations. This type of collaborative effort meets the Administration's directive to agencies to coordinate on cross-cutting issues.

Response: The EPA is aware of the PHMSA regulations and recognize that those regulations apply to the pipelines between compressor stations. While we make every effort to harmonize our rules with those of other agencies, we must rely on what we determine to be the most appropriate regulations for the industry within the constraints of the Clean Air Act.

In consideration of all the comments we received on the proposed rule, we adjusted the timing of repairs and delay of repairs as best suited for well sites and compressor stations throughout the industry. See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Jeff Addington, Manager Air Quality
Commenter Affiliation: Archrock Services, L. P. and Archrock Partners Operating LLC ((individually and collectively, ArchRock)
Document Control Number: EPA-HQ-OAR-2010-0505-6944
Comment Excerpt Number: 5

Comment: EPA has stated that its expectation is that "most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site." 80 Fed. Reg. at 56,641. This assumption is inaccurate for several reasons. First, it may be unsafe to make the repair at the time it is discovered. To repair a leak, it may be necessary to shut down the entire facility (depending on where the leak(s) are located), stop all gas flow through the compressor station, bleed off all pressure, lock out/tag out the equipment being repaired, and purge the system prior to making any repairs or replacing equipment. Depending on the operational needs, these steps may not be possible at the time the survey is conducted. Second, there may not be adequate personnel available to make repairs at the time of the survey. As explained above, Archrock is a compression service provider. Our service technicians cover a large area and may not be available to make repairs at the time our customer chooses to conduct its initial survey of its broader operations that make up the compressor station. Because in most cases we do not own the compressor station, our customer could choose to schedule the survey at its leisure - even when it is not convenient or viable for Archrock to participate. Yet for safety reasons, an Archrock service technician must make the repairs to Archrock's equipment any time repairs are required. Even if a technician is available onsite during the survey to make repairs, depending on the problem, he may not have immediate access to the specialized parts or equipment required to make the repair. Because Archrock employs over 1,000 field service technicians, it is cost prohibitive to provide every field service technician every piece of equipment or part on his truck so that he can make any conceivable repair immediately. As a result, service providers like Archrock may need to schedule a special trip to the location where the survey was conducted to repair any leaking components. For these reasons, the rule should require that repairs and resurveys should be made no later than the earliest of 90 days from the date of detection or during the next scheduled preventative maintenance event.

Response: The EPA continues to believe through conversations with stakeholders that the majority of components with fugitive emissions can be repaired at the time of the initial monitoring survey. In response to comments, we have adjusted the time period for making a repair and for delay of repair. See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8, for more information on this issue.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 14

Comment: Timeframe to repair and resurvey requires flexibility

The proposed rule states that "the source of emissions be repaired or replaced, and resurveyed, as soon as practicable, but no later than 15 calendar days after detection of fugitive emissions." The rule further states (in column 2), "if the repair or replacement is technically infeasible or unsafe during unit operations, the repair or replacement must be completed during the next scheduled shut down or within six months, whichever is earlier." Pioneer suggests that these provisions be modified to be consistent with the language in the Colorado Regulation 7, which provides more realistic flexibility for operators. First, Reg. 7 allows for delayed repairs for "good cause" which is more feasible for oil and gas operations and allows field personnel to make more of a subjective decision based on their experience. "Technically infeasible" is not defined and is a harder standard to determine and prove. Next, CO Reg 7 specifies "working days" in their timeframes versus "calendar days" as proposed in this regulation. The term "working days" to exclude weekends and holidays is more feasible and acceptable for operators. Field personnel are sparse on weekends and therefore, these days should not be counted against the required already stringent timeframes.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination. See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8, for information on repair timeframes.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 24

Comment: EPA should extend the time period for repairs after surveys from 15 to 60 days after a survey.

In the proposed NSPS, EPA proposes that compressor station operators repair the sources of fugitive emissions within 15 days after they are discovered. Once the repair has been made, the operator must then resurvey the component within 15 days to ensure that the leak has been repaired. EPA has asked for comments on whether 15 days is an appropriate time period for repair of sources of fugitive emissions at compressor stations. As discussed above, the compressor stations for a single operator are frequently unmanned, spread out over a wide geographic area, and located in remote regions. Operators would have to coordinate for the delivery of new equipment, for the arrival of contractors to perform the repairs, and then for a separate contractor to come and perform the resurvey. In remote areas, it is even more difficult to find qualified contractors and parts in a short time period. As a result, 15 days is very clearly not enough time to ensure that repairs have been made. We recommend 60 days as an appropriate time period for repair of sources of fugitive emissions at compressor stations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: John Hampp
Commenter Affiliation: NextEra Energy, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6873
Comment Excerpt Number: 12

Comment: **Leak "Repair" Frequency**

We request EPA's final rule to allow 60 days to repair identified leaks from the date of discovery rather than the proposed 15 days repair timeline. Though many "critical" spare parts are typically kept on-site, it is infeasible to have a complete inventory of all spare parts on-site and accounted for at any given time to repair all failure modes that could occur. This results in the likelihood that a given part may not be on-site or able to be procured within the 15-day repair window. Furthermore, for sites relying on contractors to perform the repair, it may take longer than 15-days to procure a vendor and then have that vendor complete the repair on time. Given the remote nature of many sites and typical leaking that may occur, we believe 60 days is reasonable to assure compliance.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 18

Comment: Comments on EPA's Proposed LDAR Monitoring Standards

EPA Must Provide Increased Flexibility for the Repair of Fugitive Emissions Leaks

Second, GPA urges EPA to clarify and provide flexibility regarding the requirement for remonitoring of leaks. As proposed, the resurvey requirements for OGI monitoring in 40 C.F.R. § 60.5397a(j)(2)(iii)(B) cross-reference 40 C.F.R. § 60.5397a(a), which requires monitoring of "all fugitive emissions components." GPA requests that EPA clarify that the resurvey requirements in 40 C.F.R. § 60.5397a(j)(2)(iii)(B) apply only to the repaired component(s) and do not create an obligation to resurvey the entire affected facility. Further, for the reasons discussed above, GPA requests that EPA extend the resurvey deadline to 60 days in accordance with the primary deadline for repairs.

Response: The EPA appreciates the commenter's attention to detail. In the rule as finalized, we have made a number of changes to §60.5397a. Paragraph 60.5397a(j)(2)(iii)(B) is now found at §60.5397a(h)(3)(iv)(B) and refers to §60.5397a(c)(7) rather than §60.5397a(a). Paragraph 60.5397a(c)(7) does not contain the language that concerned the commenter. The reference to §60.5397a(c)(7) is meant to indicate that the owner or operator should use OGI in conjunction with the elements outlined in the monitoring plan when performing a resurvey. However, we also note that §60.5397a(h)(3) clearly specifies that the resurvey requirements are only for repaired or replaced components.

Concerning the resurvey deadline, see response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 59

Comment: If EPA does not adopt these proposed revisions, EPA must be cognizant of reasonable repair times (within the limitation of resurveying only using OGI), and revise its rule language to state that each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 15 days after repair to ensure that there is no leak. Kinder Morgan does not reflect this revision in the proposed text language provided below as we assume EPA adopts Kinder Morgan's proposal to allow the operator to utilize any methodology to re-survey leaks to confirm repair.

Kinder Morgan proposes the following specific revisions to EPA's Proposed NSPS OOOOa Rule:

Proposed Revisions to EPA's § 60.5397a:

(j) For fugitive emissions components also subject to the repair provisions of §§ 60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. **Delay of repair of components for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a complete or partial facility shutdown. Repair of these components shall occur before the end of the next complete or partial facility shutdown.** ~~If the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier.~~

(2) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 15 days **of repairing or replacing such component**~~finding such fugitive emissions~~, to ensure ~~that~~ there is no leak.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using ~~either~~**any surveying method available under Method 21 for resurveying** or optical gas imaging within 15 days of ~~finding such fugitive emissions~~**repair**.

~~(ii) Operators that use Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(ii)(A) and (B).~~

~~(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background.~~

~~(B) Operators must use the Method 21 monitoring requirements specified in paragraph § 60.5401a(g).~~

(~~iii~~ii) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(iii)(A) and (B).

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (a).

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 133, DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118, and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 57

Comment: Moreover, EPA's statement that all repairs, even those that are delayed, must be completed during the next shutdown or within 6 months, whichever is earlier, is unrealistic and unnecessary. This provision de facto requires that a facility conduct a shutdown every 6 months. Many facilities are scheduled to operate with minimal or no shutdowns, while others may schedule an annual shutdown. Should EPA force these facilities to shut down every 6 months, it would need to account for the additional cost associated with these shutdowns, including lost revenue, lost product that is vented or flared during the shutdown, and the emissions associated with the venting and flaring, among other considerations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Andrew Casper
Commenter Affiliation: Colorado Oil & Gas Association (COGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6889
Comment Excerpt Number: 13

Comment: Colorado's experience with repair and inspection deadlines has also been instructive insofar as Colorado operators have learned that a more flexible, forgiving repair and re-inspection deadline is appropriate, especially given that approximately 5% of identified leaks require a delay of repair. While this number is low in terms of overall leaks, it is significant enough that flexibility is required. Although the Quad Oa proposal permits delay in repair where "technically infeasible or unsafe," the proposal provides no discussion or definition of what is meant by technically infeasible. Moreover, such limited terms fail to adequately capture all appropriate circumstances in which a delay of repair beyond fifteen days may be required, including—as experienced by operators in Colorado—considerations such as weather constraints, the availability of specific parts and equipment, etc. EPA should therefore allow at least thirty days for the initial repair and thirty days to re-survey after the repair, as well as permit operators to demonstrate good cause for any other delayed repair beyond that timeframe.

Response: Concerning defining "technically infeasible," the EPA does not believe it is possible to define every situation in which it may be technically infeasible to effect a repair. Thus any list we developed would likely be lacking in some way. Instead, we are requiring the owner or operator to keep records explaining the situation claimed to be technically infeasible for repairs. The regulatory agency can then review those records and verify the claims. Concerning the initial repair period and delay or repair period, see responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Camilla Feibelman
Commenter Affiliation: Rio Grande Chapter of the Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-6895
Comment Excerpt Number: 10

Comment: Finally, while the proposal requires that operators repair leaks within 15 days of discovery, they allow up to six months for instances in which "safety" is not an issue. This is simply too long an exception. Instead, EPA should grant no more than 60 days for the safety exception. If operators have not removed the hazard by that point, they should be required to shut-down operations at that point in order to repair the leak.

Response: See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 24

Comment: The proposed rule requires 15 calendar days for repair of any leaks detected, except where it is technically infeasible or unsafe during unit operations. The proposed rule notes this 15-day repair window is feasible, based on the industry's past experience in compliance. However, the proposed 15 day repair window actually applies to downstream facilities, not to production facilities. This is not a sufficient basis for feasibility: downstream facilities, such as gas processing plants or other large facilities, are manned 24 hours per day and 7 days a week.

These downstream facilities generally have many spare components immediately available for repairs. A remote wellsite is vastly different from a downstream facility, and as such, an operator of a wellsite requires additional time to conduct repairs.

More often than not, it is unfeasible for an operator to conduct repairs at the time of inspection. Additionally, replacement parts may not always be available. In instances where parts may be back-ordered, it is entirely conceivable that repairs could be delayed by 15 calendar days or more. For example, the state of Utah recognizes that repairs may not always be feasible due to lack of available parts. In order to get around this problem, Utah offers the following solution, which we recommend that EPA adopt in its rule as well. In the terms of one approval order, Utah stipulates the following:

- If a leak is detected at any time, the owner/operator shall attempt to repair the leak no later than 5 calendar days after detection. Repair of the leak shall be completed no later than 15 calendar days after detection, unless parts are unavailable or unless repair is technically infeasible without a shutdown. The owner/operator shall inspect the repaired leak no later than 15 calendar days after the leak was repaired to verily that it is no longer leaking.
- If replacement parts are unavailable, the replacement parts must be ordered no later than 5 calendar days after detection, and the leak must be repaired no later than 15 calendar days after receipt of the replacement parts.
- If repair is technically infeasible without a shutdown, the leak must be repaired by the end of the next shutdown. If a shutdown is required to repair a leak, the shutdown must occur no later than 6 months after the detection of the leak unless the owner/operator demonstrates that emissions generated from the shutdown are greater than the fugitive emissions likely to result from delay of repair.

Such flexible approach is consistent with the spirit and intent of an LDAR program, which is a work practice standard designed to encourage more efficient and better operations. Moreover, without language permitting operational flexibility to locate appropriate parts, there would be a significant disincentive to accurately find and fix leaks—defeating the purpose of the program. The Alliance suggests the proposed rule be modified to include a similar provision in the final rule.

Response: Concerning the initial repair period and delay or repair period, see responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination.

Commenter Name: Greg Amimon, Director,
Commenter Affiliation: Environmental Northern Natural Gas, Berkshire Hathaway Energy Pipeline Group (BHE)
Document Control Number: EPA-HQ-OAR-2010-0505-6933
Comment Excerpt Number: 7

Comment: The EPA proposes under §60.5397a(j)(2) that repaired or replaced fugitive emissions components must be resurveyed no later than 15 days of when the emissions were found. However, 40 CFR §60.5397a(j)(1) provides that "if the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within six months, whichever is earlier." There is no additional provision for resurveying of repairs or replacements which are conducted after 15 days, but no later than six months. Provisions should be added that leaks repaired or replaced after 15 days, but no later than six months, shall be resurveyed within 15 days of the repair or replacement date.

Response: The EPA has revised the regulatory text in §60.5397a to indicate that the resurvey must take place within 30 days of repairing or replacing the component. This requirement applies to both components repaired in 30 days and those placed on delay of repair.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 86

Comment: And the timetable for the urgency for leak repair should be dependent both on safety and on the severity of the leak.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 118 and DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8.

Commenter Name: Patricia Karr Seabrook
Commenter Affiliation: Miller/Howard Investments, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6818
Comment Excerpt Number: 6

Comment: In talking with companies, we understand that monitoring equipment, particularly the infrared cameras, can be expensive. We are encouraged by recent and emerging advances in continuous detection technologies for methane that will permit real time identification of large leaks, paving the way for optimized deployment of OGI cameras, faster fixes, greater emission reductions, and less cost to operators. We advocate that the final regulation reflect EPA's technology-forcing authority under the Clean Air Act by allowing and incentivizing innovation in leak detection technologies and practices, including continuous detection. Without such alternative pathways, the proposed rule risks unintentionally freezing methane detection technology at its current level.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Robert M. Gould
Commenter Affiliation: San Francisco Bay Area Physicians for Social Responsibility (SF Bay PSR)
Document Control Number: EPA-HQ-OAR-2010-0505-6819
Comment Excerpt Number: 14

Comment: Allow and incentivize innovation in leak detection technologies and practices, including continuous detection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 137

Comment: Other Fugitive Emission Detection Technologies

EPA requested comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future.

In the preamble, EPA states:

"We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM-33 approaches (e.g., Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (e.g., Rebellion photonics), and Airborne Differential Absorption LiDAR (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring surveys should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies."

Ongoing Research and Development Activities The scale up of LDAR activities under the draft rule provides a strong incentive to bring down costs while enhancing leak detection effectiveness, and is already stimulating a substantial increase in R&D investment, as EPA notes in its proposal. We call to the Agency's attention two ongoing initiatives that aim to develop improved LDAR technologies for use by companies as they seek to comply with federal and state methane emissions reduction requirements: a public-private initiative and a partnership between a number of corporate actors and an environmental non-governmental organization. These initiatives may well demonstrate within the next several years, the commercial availability of substitute technologies, equipment and approaches that are more efficient and cost-effective than the continued use of Method 21 or OGI.

Department of Energy (DOE)/ Advanced Research Projects Agency – Energy (ARPA-E). As of December 16, 2014, ARPA-E had selected eleven private sector projects involving methane observation networks with innovative technologies to obtain methane emissions reductions that would receive awards totaling some $35,000,000, (MONITOR Program). The objective is to catalyze and support the development of transformational, high impact energy technologies that can effectively promote methane emissions reduction. DOE's aim is to lower the cost of compliance through the development of low cost detection systems coupled with advanced modelling capabilities to pinpoint and quantify -major leaks and engage in mitigation prioritization with a focus on larger emitters. The proposed rule's approach, consistent with current technology, relies on detection alone as the criteria to define the need for repair without any prioritization based on the size of the leak. Generally the thrust of the work being supported by ARPA-E does not look at leaks from individual components, but will lead to examination of larger areas to identify significant leaks which can then be specifically identified and repaired. ARPA-E is planning within 6-7 months to set up a testing facility intended to serve as a site for field tests to ensure that technologies are tested in a standardized, realistic environment outside of the laboratory. This would be followed by a second round of testing to assess previously undemonstrated capabilities and further technical gains. ARPA-E believes some of these technologies could become commercially available in from 2-3 years. The goal within 18 months to 2 years is to develop a methodology to demonstrate the superiority of one or more of these technologies to OGI that do not require the manpower, the fleets of trucks and other equipment and surveys that are time-consuming to undertake and dwarf the cost to the regulated community even of an expensive FLIR camera ($90,000). Each of ARPAE's partners will need to demonstrate it can bring the costs down to $3,000 per site per year (many of which have multiple wells). The hope and expectation is that costs will be significantly lower, going down as to as little as $1,000 per site.

EDF Methane "Detectors Challenge" (MDC). In June 2014, the Environmental Defense Fund (EDF) along with five private sector partners issued a request for a proposal intended to target innovators from universities, start-up companies, instrumentation firms, and diversified technology companies among others to develop continuous methane leak detection monitoring for the oil and gas industry. They also sought expressions of interest in becoming part of the lab and field tests that would lead to pilot purchases and testing at oil and gas facilities. The initiative is intended to catalyze and expedite development and commercialization of low-cost, methane detection technologies that will help minimize emissions in the oil and gas industry. MDC is based upon the belief that shifting the methane emission detection paradigm from periodic to continuous will allow leaks to be found and fixed, more readily decreasing methane emissions significantly. The ideal system would serve as a "smart" alarm sending an alert to an operator when an increase in ambient methane is detected that reflects emissions beyond what one would normally expect to see. The "MDC program refers to cost as a critically important factor and EDF and its partners sought out technologies that could reasonably be expected to be sold for roughly $1,000 or less per well pad (or compressor site) when produced at scale over the following 2-5 years. The MDC commenced with a set of laboratory tests of five different sensor technologies in 2014, called "Phase 1." Four of these five technologies were selected for further development and assessment in a follow-up effort referred to as "Phase 2" which tested each technology developer's entire system in controlled laboratory and outdoor settings in order to ensure that the systems performed as required prior to moving into industry pilots, which is the immediate next step.

We urge EPA to stay abreast of technological developments and closely track the results of research and testing through an open dialogue with experts in the private sector and government.

Recommendations An optical gas imaging (OGI) instrument is defined in 40 CFR 60.18(g)(4) as "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye." EPA's Technical Support Document (TSD) for Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K) provides a summary of the current state of the technology for two commercially available OGI cameras, the FLIR GF320 and Opgal EyeCGas, to detect equipment fugitive leaks by infrared thermographic imaging.

EPA should write the rule to allow any new technology to be used that is equivalent to OGI or Method 21 in detecting fugitive leaks. Such new technologies should not be limited to meeting EPA's current definition of OGI (i.e. "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye."). In addition, since OOOOa is not a quantification rule, such new technologies need only demonstrate that they can detect leaks; they do not need to quantify leaks.

The Regulation Should Allow Flexibility In The Methods Used To Detect Fugitive Emissions

The Agency has asked for comment on "criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining."

A study performed by an API member company compared three basic leak detection methods: AVO, OGI, and M21. In general, the M21 approach was the most labor and time intensive, and, therefore, the most costly. FLIR methods could be implemented for less than 20% of the cost of M21 approaches. The results showed that AVO, while the least costly method, was not generally effective when compared to M21. On average, AVO found only 9% of the well pad leaks found by M21, and only 12% of the well pad site emissions calculated from M21 leaks. At the compressor station, because of the high ambient noise and close proximity of equipment, AVO method was not effective at all, and found 0% of the leaks found by M21 methods. The FLIR technique, on the other hand, was more effective.

- At well pads, FLIR finds 41% of leaks found by any method, but FLIR finds 89% of the total well pad emissions identified by any method (i.e. FLIR finds more of the larger leaks). It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 89% of the leaks, but only 31% of the total emissions (i.e. M21 finds more of the smaller leaks).
- At compressor stations, FLIR finds 46% of all leaks found by any method, but FLIR finds 96% of the total compressor station emissions identified by any method. It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 75% of the leaks, but only 15% of the total emissions.

Although AVO was not effective in this particular study, there are locations with high H2S concentrations where AVO is more effective than M21. Sites with high levels H2S should be allowed to use AVO or H2S monitoring systems to identify leaks at well pads.

For Laser Technology, Etc., How Might Performance Requirements Be Characterized?

Subpart W allows the use of an infrared laser beam illuminated instrument for equipment leak detection [§98.234(a)(3)]. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with M21 monitoring, in which case 10,000 ppm or greater is designated a leak. However, since OOOOa does not require quantification, API does not advocate establishing a specific ppm threshold for determining a leak.

A Streamlined Approval Process Is Needed For Adoption Of Alternative Technologies As They Are Developed, Shown To Be Effective And Become Commercially Available

EPA should build into its final rule an "on-ramp" that provides an alternative path for rapid substitution of new detection equipment and monitoring strategies once they are validated and shown to be effective. This should include a fast-track review process, with firm deadlines for decision-making so that alternatives to the current LDAR requirements can be approved without time-consuming amendments to the NSPS.

As a general matter, the rule should seek to establish a more streamlined "fast-track" process for approving new detection technology that can be substituted in lieu of OGI equipment whether its use does not require modification of the LDAR protocol, or is an entirely new approach (continuous monitoring).

Where a new technology has been adequately field tested and validated through the ARPA-E MONITOR or another program and meets performance specifications outlined by EPA, the rule should authorize its deployment following a review by the Agency. The review should be completed within 180-days following submission of a complete data package by the technology developer or an oil or gas company the Agency, and the technology should be deemed approved for use unless it is disapproved by the Agency within that period. This deadline should be included in the rule itself to assure expedited action.

Detection level "equivalency" should not be required as EPA has required for using OGI versus Method 21. Because new detection equipment may have very different capabilities from existing technologies, it is critical to avoid a narrow "equivalence test for approving alternative methods. Moreover, the stringency of the process and "equivalency" testing has made it impossible to get other technologies approved. The excessive requirements EPA has put under the Alternative Leak Detection Program in 60.18(g) has made it so that no company is utilizing OGI.

Colorado Regulation 7 provides a process for approving new alternative Approved Instrument Monitoring Methods (AIMM) that could serve as a basis for OOOOa:

At a minimum, the technology must be able to pinpoint the general location of leaking or venting emissions. For non-quantifying devices, the device must be capable of detecting all hydrocarbons, and testing and certification must be repeatable. Colorado Regulation 7 also requires an indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required. Colorado Regulation 7 may also require comparative monitoring with either an IR Camera or Method 21.

API recommends that EPA allow for the use of alternative monitoring that detects leaks based on the following criteria:

- Occurs at least annually
- Pinpoints the general location of the leak
- Detects the hydrocarbons found at the sites
- Testing and certification must be repeatable
- Indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: J. Roger Kelley, Director, Regulatory Affairs
Commenter Affiliation: Continental Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6963
Comment Excerpt Number: 11

Comment: Add Flexibility to the Selection of LDAR Technology.

If EPA insists on a technology-based LDAR requirement, the agency should not require that a specific technology be used for the inspections. OGI/FLIR cameras suffer from several limitations. These limitations include lack of intrinsic safety in Class I Division II environments, difficulty in proper usage due to subjectivity, extreme expense, limited supply, and lack of quantitative results.

Additionally, specifying a particular technology contributes to that technology being overpriced — as is currently the case with FLIR cameras — and destroys the free market incentive to develop new technologies and keep prices competitive. As IPAA states in its comments, there are at least a half dozen promising leak detection technologies/techniques that are being marketed or developed in addition to the well-established Method 21 technologies (PID/FID). EPA should allow these nascent technologies to flourish, which will provide the oil and natural gas production sector with multiple tools from which to choose.

Response: In the final rule we are requiring the use of either OGI or Method 21 to perform monitoring surveys. The EPA is aware of an OGI instrument that is rated for use in Class 1 & 2 in Division 1 and a Method 21 instrument that is rated for use in Class 1 & 2 in Division 1 &2. We believe that outlining the elements that must be included in a monitoring plan ensures that monitoring surveys will be performed effectively. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. .

Commenter Name: Patrick Von Bargen, Executive Director
Commenter Affiliation: Center for Methane Emissions Solutions (CMES)
Document Control Number: EPA-HQ-OAR-2010-0505-6980
Comment Excerpt Number: 3

Comment: We understand that individual companies and other trade associations focused on particular technologies will likely submit comments as to specific provisions in the proposed rule that could be improved, with the perspective that as the oil and gas industry finds more leaks, technology is readily available to repair those leaks extremely economically; centrifugal compressors and dry seal are just one example. And in keeping with some of their other comments, we would support the notion that EPA should establish a process whereby innovations in detection and repair technologies are considered to be added to any best system of emissions reduction.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Greg Rieker, Department of Mechanical Engineering
Commenter Affiliation: University of Colorado-Boulder
Document Control Number: EPA-HQ-OAR-2010-0505-7002
Comment Excerpt Number: 5

Comment: We strongly believe that the new rules should also: 1) revisit repair thresholds, with an eye towards enhanced technical capabilities, 2) establish a route for developing and certifying future methane leak detection technologies, and 3) anticipate the near-term likelihood of continuous monitoring capabilities. New technologies may only be successful in the marketplace if they provide significant cost- or time-saving advantages over current technology. Therefore, establishing technical metrics that new technologies must satisfy, and then letting the market decide which technologies to use, would avoid blocking technologies that are potentially better suited for achieving the EPA's stated goals. We believe that, to achieve this aim, the following three key areas need to be considered.

Repair threshold:

New technologies may offer significantly enhanced sensitivity over existing technologies and enable detection of leaks at or below 6 scfh. For small leaks, it is possible that shutting down operations and venting lines in order to perform leak repair could result in greater emissions than if the leak was allowed to continue. We therefore believe that leak repair thresholds, perhaps component-specific, should be established in consultation with industry.

For methane, which poses risks to climate through absorption of radiation and risks to health through reaction with other compounds (as opposed to a direct health hazard based on exposure concentration, such as with certain VOCs), we believe the repair threshold should be based on a leak rate. Since the concentration of any leaked compound depends on the distance of the measurement from the leak location, along with wind and environmental conditions, leak rates provide a better measurement of the risks detected leaks pose to the environment. In addition, emerging technologies with remote sensing capabilities can more easily measure leak rates than concentrations. We therefore strongly suggest that the new proposed rule include language that allows for leak quantification using leak rates and not concentration. Maintaining a concentration standard will discourage new technology development and not provide improved measurement of methane risks to the environment. Where current technology does not measure leak rates directly, concentration measurements can easily be translated to leak rates using EPA accepted conversions.

Pathway for emerging technologies:

We recommend that the final rule include language that creates a pathway for emerging technologies and not be limited to only OGI and Method 21. Several programs exist (e.g. the ARPA-E MONITOR program and the Environmental Defense Fund Methane Detector Challenge) that support the development of new technologies for methane leak detection from oil and gas operations. The goal of such programs is to create lower-cost, higher-sensitivity, and more rapid-response methods for leak detection. We believe that, as these new technologies become viable, it will be critical for achievement of the EPA goals to have validation and certification processes in place by which the new technologies can be accepted for leak detection and monitoring.

Accommodation of continuous monitoring technologies:

As new technologies continue to emerge, the capability to provide continuous year-round monitoring will quickly become a reality. Given this likelihood, the language in the proposed rule that states that leaks must be repaired within 15 days of detection could push industry away from technologies that make continuous monitoring possible. Under current practices, industry has the ability to 'choose' when to monitor each site (for example within a 6 or 12 month window). Monitoring and repair can then be distributed over time based on various business factors (holiday seasons, etc.). We believe the EPA rule should extend the length of the leak repair window for leaks detected with continuous monitoring devices to match the period available for monitoring compliance with periodic technologies (e.g. OGI). For example, if sites must be monitored semi-annually under the new rule, then the leak repair window for leaks detected with continuous monitoring equipment would be 6 months. A rule change of this character would diminish perverse incentives that could value periodic monitoring over continuous monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies. We note that the final rule allows monitoring surveys to be performed with OGI or Method 21, and as such, the requirements are generally written in a way that is tailored to those technologies. In the pathway we have laid out for emerging technologies, we request that applicants provide information tailored to the new technology, e.g. action level (repair threshold), restrictions for use, frequency of measurement, etc. Different elements may need to be included in the monitoring plan and other recordkeeping and reporting requirements may be needed for new technologies, but this information can only be determined once we have information on the technology.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 57

Comment: EPA Should Create a Pathway that Incentivizes Innovations in Monitoring Technology

Equipment leaks are a significant source of methane emissions from facilities across the oil and natural gas sector. We discussed earlier in this section several recent studies suggesting that these sources could be even larger than previously understood, due both to systematically significant leaks and large super-emitters.

As noted above, several states and leading companies have been deploying instrument-based LDAR, using technologies like OGI cameras to detect leaks. These technologies are effective, though leaks will continue until facilities are surveyed.

At the same time, as we describe above, advanced LDAR technologies are being swiftly developed. Accordingly, we encourage EPA to design standards in a way that rewards innovation by providing an equivalency pathway. The key test should be whether such alternative technologies will achieve equal or greater emissions reductions. Other considerations are pertinent to making this assessment, including:

- Frequency. As described above, technologies that enable more frequent (and indeed, continuous) monitoring can minimize emissions by ensuring leaks do not persist until the next scheduled survey and catching intermittent leaks that would be missed entirely.
- Accuracy. Minimum detection limits should be sufficiently sensitive to permit accurate detection of leaks comparable to those detected by existing technologies.
- Robustness. Technologies should be capable of reliably operating in adverse meteorological conditions.

When determining equivalency, EPA should assess these technologies holistically. For instance, a system that is capable of continuous detection may identify a large number of leaks simultaneously across facilities, resulting in the need to prioritize repairs and possibly modest delays at certain sites. However, such a system could still outperform semi-annual surveys given the far earlier detection. Evaluation of these technologies should recognize their potentially substantial real-world benefits.

It is likewise important to ensure that any determination of equivalency is administratively reasonable, clear, and timely. This process must be fully transparent: the resulting assessment and determination should be publicly available and should be designed to foster strong public confidence in the rigor of EPA's determination. Any party should be permitted to make an equivalency request. EPA's standard should include a clear deadline for acting on a submitted request—e.g., between three and six months. It should also include clear, fact-based criteria for determining whether an alternative system or technology is securing equal or greater emission reductions.

The equivalency determination needs to be broad in another important dimension: creating flexibility for different technical sensing strategies. Methane and VOCs are frequently co-emitted, with methane being prevalent at production sites. 80 Fed. Reg. at 56,635. Further down the supply chain, methane emissions predominate even more strongly over VOCs. *Id*. at 56,640. Because of the commingling of pollutants, methane emissions are in many circumstances (particular upstream of processing plants) a good indicator for VOC emissions, and a response to fix a leak will address both pollutant types in one measure. Current trends indicate that emerging low-cost technology with the highest readiness level detects methane only. To keep the focus on environmental outcomes and create space for such advancing technologies, EPA's equivalency determination should look to the emissions result rather than the sensing mechanism itself. In other words, if a detection system achieves equivalent reductions in methane and VOCs as the BSER, it does not matter that the system only measures methane emissions.

Finally, the standards should be designed to incent competition in the leak detection market by eliminating duplicative requirements as technologies are proven to be equivalent. For example, periodic OGI monitoring should not be required for operators that have adopted an approved alternative work practice such as continuous detection systems. EPA should also examine the rest of the standard and eliminate redundant aspects that would no longer add value.

EPA has included numerous such alternative pathways under existing section 111 programs:

- The general provisions related to monitoring expressly provide "[a]fter receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part. 40 C.F.R. § 60.13(i).
- Likewise, the NSPS for petroleum refineries includes work practice standards for flares and, along with those standards provides "[e]ach owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant

achieved by the controls required in this section." *Id.* § 60.103a(i). These regulations also allow equipment manufacturers to apply for equivalency determinations.

- Subpart VVa includes similar procedures applicable to equipment leaks at chemical manufacturing facilities. *Id.* § 60.484.

Given these past examples and the rapid development of LDAR technologies that can both enhance environmental benefits and dramatically lower costs, we respectfully urge EPA to include in its final section 111 standards a compliance pathway that recognizes and incentivizes this technological innovation.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7002, Excerpt 5.

Commenter Name: Interfaith Center on Corporate Responsibility (ICCR)
Commenter Affiliation: Interfaith Center on Corporate Responsibility (ICCR)
Document Control Number: EPA-HQ-OAR-2010-0505-7068
Comment Excerpt Number: 9

Comment: In talking with companies, we understand that monitoring equipment, particularly the infrared cameras, can be expensive. We are encouraged by recent and emerging advances in continuous detection technologies for methane that will permit real time identification of large leaks, paving the way for optimized deployment of OGI cameras, faster fixes, greater emission reductions, and less cost to operators. We advocate that the final regulation reflect EPA's technology-forcing authority under the Clean Air Act by allowing and incentivizing innovation in leak detection technologies and practices, including continuous detection. Without such alternative pathways, the proposed rule risks unintentionally freezing methane detection technology at its current level.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 100

Comment: My goal here today is not to directly talk about the mechanism for regulation, but to discuss the work that we've recently done with the Environmental Defense Fund through the Methane Detector Challenge, the significance of which may be able to reduce methane leaks.

The Methane Detector Challenge was aimed at bridging the gap between the oil and gas providers like Shell, Anadarko, and technology providers like us to develop economically feasible and field ready units capable of continuously monitoring methane emissions from oil and gas installations.

Continuous monitoring is currently too expensive to deploy in the field, but recent science indicates that leaks are probably higher than current inventories and can occur at irregular times.

The Methane Detector Challenge aims at match -- at creating detection systems that will be available at drastically lower costs with faster time to market.

The end users -- the end users in this case, the oil and gas industry, would have available these resultant products which allows them to improve processes from modern methane real time allowing for organized responses to take place in hours, not months, with modern infrastructure. It would also allow operators to ensure the social rights to operate and gain insights from the field that help prevent leaks.

For technology providers like us, the methane detector challenge provides relevant specifications and detailed installation conditions that allow us to tailor our technologies to specific need.

We have developed such a system that has performed well through two rounds of testing at Southwest Research Institute. Our unit has been tested in a laboratory. People detecting ppm levels of methane within a test chamber and also outdoors for eight weeks in the San Antonio summer. It was successfully detected in controlled releases of methane with flow rates down to about one centimeter cubic feet per minute located up to nearly 100 feet away.

Our unit will likely be selected for further tests with an industrial operator in 2016.

As this innovation and other innovations become commercially available, we would like to emphasize that regulation must allow and incent the deployment of innovative technology capable of streamlining the processes of detection to fix leaks quickly, to prevent methane emissions and product waste, and improve operational efficiency.

Any regulations need to have a clear pathway for operators to be recognized for using innovative technology, including continuous monitoring. Without such a pathway, the proposed rule risks freezing methane detection technology as it is today at its current level.

I understand the EPA has asked for comments on how to encourage technological advancement in the methane rule.

I'm not a policy expert. I'm an engineer. So I will only reinforce that such a pathway for innovation in the final rule is very important for myself and other technology suppliers.

It is my hope that my voice in this forum will better inform and enable additional contemplation of how to best incentivize the rollout of innovations, such as our continuous methane detection unit that has been developed, and put through its paces in our participation at the EDF's Methane Detector Challenge.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 7

Comment: EPA proposed that a source develop a corporate wide fugitive emissions monitoring plan, including a number of specific requirements for the OGI technology. The Division is concerned that EPA's proposed OGI specifications will limit the development and use of alternative monitoring technology and methods, as discussed above, and that a number of the elements required in the corporate wide monitoring plan are subjective and may be difficult to enforce. For example, procedures to ensure adequate thermal background, define a walking path, and deal with interferences are subjective and depend on technical expertise. Similarly, the training and experience needed prior to performing surveys is also likely to be subjective and company specific. The Division suggests that EPA consider manufacturer specifications and recommendations to define the necessary training, operation, and operating condition requirements for the manufacturer's specific OGI technology.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7002, Excerpt 5.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 132

Comment: Thresholds for M21 Leak Definition and Repair

EPA requested comment on whether the fugitive emissions repair threshold for M21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold). In addition, EPA solicited comment on whether 500 ppm above background is the appropriate repair resurvey threshold when M21 instruments are used or if not, what the appropriate repair resurvey threshold is for M21.

Tables 9-14, 9-15, and 9-16 of the CTG draft show the summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000, 2,500, and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual, and quarterly).

For leak repairs that are not repaired during the initial survey, Subpart OOOOa allows either an OGI or M21 test with a leak threshold of 500 ppm to confirm that it is repaired [§60.5397a(j)(2)(i) and (ii)]. If M21 is used to repair the leak, then the leak definition should instead be 10,000 ppm instead of 500 ppm. A leak definition of 10,000 ppm is consistent with the leak definition used in NSPS Subpart KKK for valves at natural gas processing plants, which references NSPS Subpart VV. Also, OGI monitors detect leaks at approximately 10,000 ppm. Even in OOOOa for a gas plant, all the components do not have to meet 500 ppm. In addition, API demonstrated in comments provided to Docket ID Number EPA–HQ– OAR–2010–0505 (Proposed Rulemaking – Oil and Natural Gas Sector Regulations Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution, November 30, 2011) that there is only a small incremental difference in emission reductions between a leak definition of 500 ppm and 10,000 ppm.

Based on data in a leak detection study that compared M21 to FLIR, approximately 85% of FLIR-found leaks were over 0.1 scfh, as quantified by HiFlow. Using the correlation equation from the 1995 Protocol for Equipment Leak Emission Estimates and the average density of the field gas in the corresponding asset areas, 10,000 ppm corresponds to a leak rate range of 0.07 to 0.15 scfh depending on the component type leaking. Based on this, the study found that approximately 70% of FLIR-found-leaks were over 10,000 ppm.

Therefore, consistent with the valve leak detection provided in NSPS Subparts KKK and VV, and given that OGIs typically detect leaks over 10,000 ppm, the repair leak definition should be changed in proposed §60.5397a(j)(2)(ii) from 500 ppm to 10,000 ppm.

Response: We disagree with the commenter that the leak definition when using Method 21 should be 10,000 ppm. In order to use Method 21 as an alternative to OGI, as OGI represents BSER, the GHG and VOC emission reductions under Method 21 must be at least as stringent as under OGI. We determined the emission reductions for Method 21 at a leak definition of 10,000 and 500 ppm and found that the leak definition of 10,000 ppm resulted in lower emission reductions than OGI, while 500 ppm resulted in greater emission reductions than OGI. Therefore, we could not use a leak definition of 10,000 ppm with Method 21, and instead, we finalized a leak definition of 500 ppm. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more details regarding this issue.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 19

Comment: The proposed rule requires operators to resurvey a repaired leak with only Method 21. This is impractical. Without precise quantification, an OGI camera can detect emissions to about 10,000 parts per million (ppm); yet the resurvey using Method 21 requires repairs to a 500 ppm leak threshold. We recommend revising the resurvey/repair threshold using Method 21 to 10,000 ppm to maintain consistency between the two methods, provide the same 10,000 ppm threshold for leak detection (with OGI) and repair survey and avoid a scenario where emission are not detected via the OGI (because they are less than 10,000 ppm) but they are detected using Method 21. The difference in emissions between a 500 ppm leak and a 10,000 ppm leak is *de* *minimis*; so maintaining this consistency would not compromise the program's environmental benefits.

In addition, revising the proposed rule to reflect a 10,000 ppm leak threshold is consistent with existing NSPS equipment leak standards. *See e.g.*, NSPS, Subpart VV, 40 C.F.R. §§ 60.482-2(b)(1), 60,482-7(b), 60.482-8(b) (providing a leak detection threshold of 10,000 ppm for certain pumps, valves, pressure relief devices and connectors and identifying a "repaired" leak in § 60.281 as when "equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482-2(b)(2)(ii) and (d)(6)(ii) and (iii), 60.482-3(f), and 60.482-10(f)(1)(ii), is re-monitored as specified in § 60.485(b) to verify that emissions from the equipment are below the applicable leak definition"). *See also* NSPS, Subpart KKK, 40 C.F.R. § 60.632(a)(requiring compliance with NSPS, Subpart VV).

Response: The EPA agrees with the commenter that OGI should be allowed for resurveys and has revised the final rule accordingly. However, we are not revising the leak definition for Method 21 from the proposed level of 500 ppm. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 132.

4.9 Monitoring Plan

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 10

Comment: Additional LDAR inspection elements

EPA requested comment on whether other techniques in conjunction with OGI could be required elements of the monitoring plan to help identify leaks. The Division suggests EPA include visual or AVO inspection requirements to complement the NSPS OOOOa LDAR program. Colorado's regulations require a number of additional inspection elements to ensure that owners and operators of storage tanks comply with the "no venting" standard, and that owners and operators of well production facilities monitor and repair leaking components. Colorado established these additional requirements to ensure these facilities were more frequently observed and maintained, thus further reducing emissions.

Response: The EPA does not agree with the commenter that it is necessary to specify visual or AVO inspections in addition to the required fugitive monitoring surveys. However, we note that owners and operators must maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers a leak through audio, visual or olfactory monitoring, the owner or operator has a general duty to repair these components. . See response to DCN EPA-HQ-OAR-2010-0505-6993, Excerpt 5.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 144

Comment: 27.6.4 Visual Inspections Are Part Of Regular Operational Activities And Should Not Be Required In A Formal Protocol

EPA is seeking comment on page 56612 of the preamble on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation. These types of observations are part of regular operational activities and should not be required in a formal protocol.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 10.

Commenter Name: P. DeMarco
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5167
Comment Excerpt Number: 7

Comment: Annual or semi-annual data collection is insufficient to protect the public health. Continuous monitoring stations should be required for every unconventional oil and gas facility that is within five miles of residences, businesses, schools, parks or populated areas. The data from such monitoring stations should be publicly available, and local authorities should be notified when levels exceed established limits of safety.

Response: We disagree with the commenter that the required frequency of fugitive monitoring is insufficient to address the emissions from the affected facilities in the oil and natural gas segment. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

At this time, we do not believe that cost-effective continuous monitoring technology exists that would provide adequate data on fugitive emissions. Likewise, we do not agree that ambient air monitoring stations will adequately address emissions from these sources. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 175

Comment: I support routine monitoring proposed, although I believe that more frequent monitoring as well as real-time monitoring, when feasible, and preferably by independent entities, would be very appropriate to assure the adherence to the limits for methane and VOC emissions.

Response: The EPA appreciates your support of the proposed standards and have finalized the rule with the most frequent monitoring found to be reasonable. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

At this time, we do not believe that cost-effective continuous monitoring technology exists that would provide adequate data on fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 46

Comment: We also think that inspections should occur monthly so that we can really keep on top of implementation.

Response: The EPA disagrees that monthly inspections are necessary to address the fugitive emissions from these sources and have finalized the rule with no inspection requirement. However, we note that owners and operators must maintain and operate affected facilities with good pollution control practices to minimize emissions. Therefore, if an owner or operator discovers a leak through audio, visual or olfactory monitoring, the owner or operator has a general duty to repair these components. Additionally, we have finalized the rule with more frequent monitoring than proposed for compressor stations (quarterly) and the proposed semi-annual monitoring for well sites. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 211

Comment: Inspections for leaks must be uniformly required at a higher frequency than they are under current rules. They need to be required on at least a monthly basis. Leaks must be required to quickly be fixed, once they're detected, and not allowed to persist for six months or longer without action. This is health and safety we're dealing with, not inconsequential matters. And it's been shown that while some operators will do their best to go beyond compliance with the rules, we've seen, time and time again, that many do not. It must be required and it must be enforced with proper inspection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7337, Excerpt 46, for information on monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 2, for information on equipment repair.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania

Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 64

Comment: Inspections should occur monthly for all well sites and compressor stations for leak detection and repair requirements.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7337 excerpt 46.

Commenter Name: Richard W. Corey, Executive Officer
Commenter Affiliation: California Air Resources Board (CARB)
Document Control Number: EPA-HQ-OAR-2010-0505-6942
Comment Excerpt Number: 4

Comment: ARB also recognizes the importance of super-emitters in controlling methane emissions as a small percentage of equipment can lead to the majority of emissions. Several recent studies have confirmed the disproportionate impact of super-emitters to total methane emissions. Our analysis in the Low Carbon Fuel Standard estimate that less than 1% of components account for a majority of emissions for oil production. Given this fact, strong leak detection and repair programs as well as enforcement is necessary. ARB commends the proposed semi-annual approach and recommends consideration of more frequent surveys.

Response: The EPA appreciates the commenter's support. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 166

Comment: The Alliance is encouraged by the semiannual monitoring frequency and believes such frequency is supported by the data.

Response: The EPA appreciates the commenter's support. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)

Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 12

Comment: For natural gas well sites bi-annual well site inspections should be acceptable. Requiring twice annual inspections with thousands of wells would be uneconomical and the lack of time to spend on each site would produce poor quality inspections.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Cory Hansen, et al.
Commenter Affiliation: Institute for Policy Integrity at New York University School of Law
Document Control Number: EPA-HQ-OAR-2010-0505-6931
Comment Excerpt Number: 8

Comment: The Proposed Rule requires that operators use Optical Gas Imaging (OGI) to inspect "fugitive emissions components" for methane leaks, a process by which cameras reveal otherwise invisible gas leaks. As discussed above, EPA analyzed three options with different baseline inspection frequencies. EPA's selected alternative, Option 2, requires baseline semiannual inspection performed at newly drilled or re-fractured oil and natural gas well sites, new or modified gathering and boosting stations, and new or modified transmission and storage compressor stations. Option 2 is expected to reduce methane emissions by 60 percent; the more stringent Option 3 is expected to reduce emissions by 80 percent and increase corresponding costs and benefits.

Under the Proposed Rule, following baseline semiannual inspection, a sliding scale adjusts inspection frequency depending on the percentage of leaking components identified using OGI technology:

Rather than using these arbitrary schedules, EPA should set OGI inspection frequency in order to maximize net benefits. The Regulatory Impact Analysis does not explain how it arrives at semiannual inspection as the optimal survey frequency. EPA recognizes that "fugitive emissions may be underestimated based on emerging studies," so the benefits used in EPA's calculations are a conservative lower bound. And in estimating the cost of OGI, EPA uses a linear model that makes semiannual inspection twice as expensive as an annual inspection and quarterly inspection four times the cost. In reality, this will only be the case should a firm contract out the inspection with such a fee structure. If a firm purchases the OGI equipment, the cost would be amortized over its useful life. As the frequency of inspection increases, the number of leaks detected should increase, as well as the emissions recovered. Considering the greater potential for large leaks in older equipment, a factor not expressly considered in EPA's analysis, semiannual inspection may not be the most socially optimal inspection frequency.

Thus, there are several additional factors that EPA could have considered in its benefit-cost analysis with respect to OGI frequency, including but not limited to: the effects of aging equipment on leak frequency and magnitude; the price and availability of OGI technology for purchase; the cost of repeated inspections; the episodic nature of large leaks; and potential technological advancement of OGI technology and its effect on price. Ideally, EPA should use cost-benefit analysis to determine the socially optimal level of OGI frequency. And regardless of how stringently EPA sets OGI frequency rates now, EPA should plan to gather information about compliance cost and inspection efficacy on an ongoing basis, and schedule retrospective review to fine-tune OGI frequency requirements in the future.

Response: We agree with the commenter and have removed the performance based monitoring frequency provisions and retained a fixed monitoring frequency for well sites and compressor stations in the final rule. Chapter 4 of the Technical Support Document provides the analyses that were performed for the fugitive monitoring sources and the RIA provides the determination of BSER. Many of these emerging studies only provide small sampling sizes or are based on small areas of the country. The data from the EPA Equipment Leak Protocol document and the EPA/GRI study provide nationwide equipment leak data on a component-level basis and are derived from a robust data set. With regards to cost, the fugitive emission analysis was not based on a linear model, but evaluated at each of the monitoring frequencies. Actual costs for conducting OGI monitoring using a contractor were used, in addition to assumptions for repair and resurvey of components, as well as the time associated with developing a modeling plan, recordkeeping and reporting.

We believe our BSER analysis has taken into account the factors that the commenter provided. The equipment data includes an average of both new and old equipment. We also conducted an analysis for a company purchased OGI in the memorandum "Evaluation of Cost Methodologies for Optical Gas Imaging (OGI) Monitoring" available in the docket. We also analyzed the episodic nature of leaks in the memorandum "Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program" also available in the docket. We will continue to gather data for equipment leaks and determine if changes to the final rule are warranted in the future. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for information on the determination of monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 150

Comment: More must be required from the sources that will be subject to the proposed regulations. For instance, leak detection and repair must be conducted more often. And the failure to report leaks should not be reported. Monthly LDAR should be mandated for all sites. A site should never be allowed to go for a year without equipment base being checked. LDAR monitoring frequency "step down" incentivize operators to fail to find and report leaks. This is bad policy that encourages operators to act contrary to the public interest.

Response: The EPA has analyzed all available data to determine the most appropriate monitoring and repair frequency and has finalized a semiannual monitoring frequency for well sites and a quarterly monitoring frequency for compressor stations. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for information on the determination of monitoring frequency. We have also finalized the rule with fixed monitoring frequencies with no performance based "step down". See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 8

Comment: We recommend that the frequency of leak monitoring for transmission and storage (T&S) compressor stations be revised to annual instead of the proposed semi-annual monitoring requirements.

Response: The EPA disagrees with the commenter that the leak monitoring frequency for transmissions and storage compressor stations should be annual in contrast to the proposed semi-annual requirements. To the contrary, based on review of costs and emissions reductions information for the final rule, we determined that quarterly monitoring for these sources would be cost effective and finalized the rule with quarterly monitoring frequency for compressor stations. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for information on the determination of monitoring frequency.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 1

Comment: For compressor stations, fugitive emissions (leaks) are not in the best interest of a natural gas producer, leaking methane means less methane to sell. Twice yearly monitoring after start-up or modification is therefore overkill and arbitrary. The incentives for minimizing leaks and punishment for leaks written in the proposed rule are also unnecessary. Annual monitoring would be sufficient and more enforceable with less room for error on the part of operators and inspectors.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6946, Excerpt 8.

Commenter Name: Will Whisenant, Safety and Security Operations Coordinator
Commenter Affiliation: Virginia Oil and Gas Association (VOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-7047
Comment Excerpt Number: 6

Comment: For gathering and boosting stations, twice annual required optical gas imaging is overkill, match up with FERC regulations or only require annual surveying

Response: See response to DCN EPA-HQ-OAR-2010-0505-6946, Excerpt 8.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 11

Comment: The quarterly and semi-annual LDAR requirement should be removed as it has not been proven to be any more effective than less frequent surveys. From a cost/benefit standpoint, EPA has already determined quarterly monitoring to not be economically feasible so it's inclusion in this proposal is puzzling. Furthermore, LDAR programs relying on percentages of leaking components to determine the survey frequency do not consider all the factors that contribute to fugitive emissions and are thus flawed in design. The "diminishing returns" aspect (operators find fewer leaks with each subsequent inspection) of LDAR dictates that the variable survey frequencies result in overly burdensome recordkeeping requirements for operators with no associated tangible emissions reductions. The MSC recommends that the LDAR surveys should be required at a static annual frequency at larger sites with equipment such as a compressor or storage vessel to maintain the integrity of the intended purpose. The MSC feels that sites with equipment configurations or component counts less than the model plants should be exempt from the LDAR requirements. As based on U.S.EPA's analysis, LDAR is not cost effective at sites with less equipment and fewer components.

Response: The EPA does not agree with the commenter that fugitive monitoring is not more effective at more frequent survey rates. We have reviewed the costs and emissions based on comments and have determined that semi-annual monitoring for well sites and quarterly monitoring for compressor stations is cost effective. We also established a third model plant that represents a lower component count arrangement and have found the requirements to still be cost effective. We do not agree that sites with component counts less than the model plant should be exempt, because the cost effectiveness analysis is based on a model plant that represents an estimated average of the component configurations and therefore, smaller sites are considered in that average. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

The EPA agrees with the commenter that the variable survey frequencies based on level of leaking components or other criteria is overly burdensome and have removed those provisions from the final rule. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 20

Comment: PAW does not agree with the proposed variable frequency of LDAR. PAW operators do not see a significant change in emissions for survey frequencies higher than annually. As a practical example, a member company conducted eight infrared (IR) LDAR surveys of their well pads over the past five years. The most recent monitoring program conducted in November 2013 included over 284,000 components at 637 wells on 28 pads (at the time this was an estimated 80 % of the total wells in the field). The data collected to date demonstrate the following:

- The field-wide leak rate is consistently close to 0.1% (1 leak per 1,000 components);
- The 99% confidence interval leak rate is consistently below 0.2 % (less than 2 leaks per 1,000 components);
- Leak rates are similar for all pads, regardless of whether they have been previously surveyed with an IR camera or not; and
- The leak rate does not vary depending on the interval between IR camera leak surveys.

The same company conducted multiple semi-annual LDAR inspections with minimal reduction in leakage rates. Over the five year monitoring history average leak rates have dropped from 0.08% to 0.06%, equating to one less leaking component per 5,000 components monitored. In addition, these inspections have shown that leakage rates are minimal and remain minimal. Therefore, this experience coupled with similarly reported experiences in API comments can only conclude that an increased frequency of inspections will not result in a net environmental benefit of reduced emissions. While PAW acknowledges the benefit of LDAR programs and inspections, evidence indicates that quarterly inspections do not contribute to greater emissions reductions than annual inspections. The company's five years of semiannual monitoring data supports a reduction in monitoring frequency to a fixed frequency of annual rather than an increase in monitoring frequency to quarterly or a variable more frequent schedule.

Response: We disagree with the commenter's assessment that increased frequency of inspections do not result in reduced emissions. One environmental benefit of increased frequency of inspections is that owners or operators may find components with fugitive emissions sooner. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 44

Comment: EPA provides no justification that a fugitive emissions monitoring schedule more aggressive than annually provides any meaningful environmental benefit; and in fact, pertinent data indicate that the benefits of an LDAR program do not in fact increase with increased frequency of inspection.

As expected, the number of leaks identified was highest at the first monitoring event; however, after that first monitoring event, the number of leaks identified drastically declined for nearly a two-year period. The data indicate that the number of detected leaks decreases significantly after the first inspection (and repair) and stabilize (if not continue to decrease) for a period not less than a year; thus, supporting Kinder Morgan's position that annual monitoring is more than adequate to reduce emissions in a cost-effective manner.

In conclusion, Kinder Morgan believes its request for annual monitoring is reasonable, particularly in light of the fact that EPA itself concedes "that duplicative recordkeeping and reporting requirements may exist between the NSPS, Subpart W, and other state and local rules" and EPA is actively "trying to minimize overlapping requirements on operators." The proposal presented by Kinder Morgan in this Section F directly addresses and would resolve any concern of duplicative reporting requirements and unnecessary burdens. Furthermore, Subpart W data, EPA's own cost analysis, and Kinder Morgan's past experiences with LDAR programs demonstrate that beyond annual monitoring and reporting, the fugitive monitoring program fails to attain increased benefits proportionately with the investment and effort to implement the same.

Response: We understand that the implementation of a fugitive monitoring and repair program may find more leaks at the beginning of the program due to improper installation or defective equipment or components. However, data from leak programs show that after the initial survey, leaks reoccur at components that were repaired, in addition to new leaks that form due activities such as the wearing down of valve packing or improperly reseated PRDs. With respect to the commenter's claim that leaks identified during surveys diminish over time, the EPA does not have data that supports that supposition. We do have data that supports the premise that leaks continue to occur at intervals and those intervals vary significantly. The monitoring and repair programs are intended to limit the emissions from these reoccurring and new leaks through periodic monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, and section 4 of the TSD for further discussion.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 15

Comment: For fugitive emissions from well sites and compressor stations, EPA is proposing that new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) conduct fugitive emissions surveys semiannually with OGI technology and repair the sources of fugitive emissions within 15 days that are found during those surveys. EPA is co-proposing OGI monitoring surveys on an annual basis for new and modified well sites, and requesting comment on OGI monitoring surveys on a quarterly basis for both well sites and compressor stations.

- CONSOL believes that OGI technology monitoring should be required on an annual basis at new and modified well sites and compressor stations. EPA has not demonstrated how increased monitoring and record keeping is more effective for detecting and preventing the state requirements and operator best management practices that are already in place. It should remain within the authority of the state regulatory agencies and the best management practices of the operators to implement additional monitoring when it is actually needed.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 44. The final rule is designed to complement current state and other federal regulations. We carefully evaluated existing state and local programs when developing these federal standards and attempted, where practicable, to limit potential conflicts with existing state and local requirements. However, we recognize that in some cases these rules require more stringent regulatory provisions and in other cases may be less stringent than current state rules. After careful consideration of all of the comments, we are finalizing the standards with revisions were appropriate to expand the source category, promote gas capture and beneficial use, and provide opportunity for flexibility and expanded transparency in order to yield a consistent and accountable national program. See discussion in the State LDAR comparison Memo in the Oil and Natural Gas docket for more information on this topic.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 36

Comment: Finally, recordkeeping costs under the Proposed Rule will exceed the costs of the survey itself. EPA should require an annual survey instead of a semi-annual survey to reduce these costs.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. The EPA does not agree that recordkeeping cost under the rule exceed the costs of the survey. Commensurate with changes we made to the final rule from the proposed rule, we reviewed the recordkeeping and reporting requirements and were able to reduce those requirements in many area. The records for monitoring surveys are prepared during the survey and are included in the cost of the survey. The only other cost is maintaining the records, which we do not believe is burdensome.

Commenter Name: John Hampp
Commenter Affiliation: NextEra Energy, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6873
Comment Excerpt Number: 13

Comment: For leak "monitoring" frequency, we urge the EPA to require an "annual" monitoring leak survey frequency rather than a "quarterly" frequency. Requiring a quarterly frequency would stress man-power and likely require increased costs from vendors. Given the frequency at which leakages to equipment occur, an annual monitoring frequency is more reasonable to assure compliance and implement the health and environmental goal.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 13

Comment: The EPA has proposed OGI technology with semiannual surveys as the BSER for detecting fugitive methane emissions from new and modified well sites, compressor stations. The EPA in page 56636 conveys "the costs between annual and semi-annual monitoring are comparable. Because semi-annual monitoring achieves greater emissions reduction, we focus our analysis on the cost based on semiannual monitoring". When reviewing the frequencies of monitoring surveys in making its BSER determinations, EPA relied on the quantity of methane emissions reductions (as noted in Table 2) and not necessarily the cost-effectiveness ($/ton) as noted in the table below (cost of controls presented below are without gas savings).

	Single Pollutant		Multipollutant		
	Annual	Semi Annual	Annual	Semi Annual	Source (TSD)
Well Site Weighted Average	$2,475	$2,768	$1,237	$1,384	Table 5-14, 5-15
Compressor Station Weighted Average	$686	$718	$343	$359	Table 5-17, 5-18

The EPA proposed analysis clearly shows that annual surveys is clearly more cost-effective than semiannual surveys. A cost-effectiveness analysis provides a means of evaluating whether one technology or work practice yields reductions relative to resources spent. As noted earlier, one can realize significant cost reductions when adopting a Corporate-wide or custom programs in lieu of EPA mandatory programs, mainly due to economies of scale and avoiding efficiencies by having a single program for operators to adhere to.

The EPA appears to use the 40/60/80 percent reduction tiers for annual/semi-annual/quarterly monitoring surveys associated with the Colorado Regulation 7 rulemaking. Observation of SWN's fugitive emissions monitoring surveys (voluntary and regulatory driven) does not appear to reflect or support similar reductions associated with the increased frequency of surveys.

In addition based on SWN's fugitive emissions monitor survey data, which includes Hi Flow measurement of leaks, we believe the emissions factors used by EPA for fugitive component emissions at well sites and compressor station sites are not current or representative. The data represented in the Technical Support Document and Regulatory Impact Analysis appears to be from the 1996 GRI report. This report reflects the results of measurements made in 1992 time frame and on a limited number of well sites and compressor stations.

Using the 40 CFR part 98, Subpart W default average component counts for major equipment, SWN calculated the estimated number of valves, connectors, PRVs, and open ended lines for approximately 3071 wells subject to SWN SMART LDAR program in 2014. The table below reflects the differences in emissions when using the EPA fugitive component emissions factors and SWN HiFlow measurement data. The results indicate that, at least for SWN, the EPA factors yield a much higher emissions rate (which has implications to "cost effectiveness" evaluations, actual reductions, etc.).

	EPA Emissions Factors	SWN HiFlow Data
	MMSCF CH_4	MMSCF CH_4
SWN Production	250.21	58.15

Recommendations:

Based on the comments above, SWN does not agree with EPA's determination that semi-annual monitor surveys are BSER. Based on SWN's fugitive emissions survey experience, we believe that an initial fugitive emissions survey followed thereafter by an annual fugitive emissions survey is adequate to control fugitive component emissions leaks. Therefore we recommend that EPA revise the fugitive emissions survey frequency to (a) initial followed by (b) annual.

Response: With respect to the lower cost effectiveness of annual compared to semiannual monitoring, the EPA agrees with the commenter that the cost effectiveness is lower. However, in determining BSER cost effectiveness is not the only criteria and we consider the overall environmental benefit, particularly where we see more than one option that we consider to be cost effective. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

For proposal, the EPA used the best estimates available for the control efficiencies achievable through fugitive emissions monitoring and repair programs. In the interim, we have not obtained data from commenters or other sources supporting other levels of control. Accordingly, in the absence of improved estimates, we have used the same control efficiencies in the final rule analyses.

With regard to the commenter's analysis of emissions factors based on subpart W data, we reviewed data from subpart W and the GHG Inventory and found that the data from these two sources are based on the EPA/GRI study. Therefore, no changes were made to the source of data for the fugitive emission estimates. We did however, remove sources of emission from compressor stations that are intended to vent, and therefore are not fugitive emissions. We also updated our model plant based on equipment and component information contained within the GHG Inventory.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 9

Comment: As an initial matter, the Alliance supports no more than an annual LDAR frequency for all sources. While we stated during initial public comment that we were encouraged by the move away from quarterly to semi-annual, upon further review of the rule we do not believe a semi-annual frequency requirement is a cost-effective approach. In this respect, we support the other national trade associations. The following discussion provides a basis for this comment as well as a critique of the proposal's over-reliance on Colorado's program.

EPA solicits comments on the appropriateness of the percentage of emission reduction level that can be achieved with quarterly, semiannual, and annual monitoring program frequencies. *See* 80 Fed. Reg. at 56,635. As an initial matter, the rule "find[s] that the cost of monitoring/repair based on quarterly monitoring at well sites using [optical gas imaging or "OGI"] <u>is not cost-effective</u> under either [the single- or multipollutant approach]." 80 Fed. Reg. at 56,636 (emphasis added). Given the inaccuracies in assessing costs, as described in more detail below, the Alliance agrees with this conclusion. The Alliance believes that if more accurate cost and benefit data were used, quarterly monitoring would be even more costly per ton of pollutant reduced (i.e., even less cost-effective) than estimated in the proposal. In light of this express finding, there does not appear to be any legal authority to impose a "step-up" approach that would require operators with higher than a 3 percent leak rate over a 12-month period to move to quarterly monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 13, for more information on monitoring frequency and BSER determination. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 16

Comment: The Alliance supports a fixed, annual instrument-based survey for LDAR. As we stated in September at the public meeting, we were encouraged by EPA's move away from quarterly to semi-annual. Upon further review of the proposal we believe a fixed, annual instrument-based LDAR frequency is the only appropriate approach. For one, it is notably more cost-effective. Were EPA to correct the inaccurate assumptions and methodologies concerning LDAR costs (see Section II(b) above), we question whether a semi-annual frequency would remain cost-effective.

As written, the proposal requires operators to monitor leaks across an entire field, with multiple facilities, on different and changing inspection schedules. This monitoring burden is in addition to the challenges associated with calculating the leak rate at every single facility, as described above.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 13, for more information on monitoring frequency and BSER determination. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 26

Comment: The requirement for semi-annual LDAR surveys at affected oil and gas production operations is excessive. Alternatively, PIOGA supports EPA's co-proposal of LDAR monitoring on an annual basis under Subpart OOOOa.

PIOGA believes the requirement for semiannual OGI LDAR surveys is excessive and will cause a financial burden on affected entities. Data provided in the technical support document (TSD) indicates that fugitive emissions reductions from oil and natural gas well sites based on annual LDAR surveys will be 40% and semiannual LDAR surveys will achieve a 60% reduction. When considered on a macro basis as in the TSD, the difference is significant. However, the estimated reductions are achieved across many "small" sources and the financial impact of semiannual surveys on small business entities using OGI and contractors, regardless of the nationwide impact, will be substantial. PIOGA recommends that the rule be revised to require annual LDAR surveys, consistent with existing state LDAR programs, and that OGI be presented as a compliance option, not a requirement.

As stated, PIOGA believes that requiring semiannual LDAR surveys for affected facilities is excessive and believes that annual LDAR surveys are sufficient.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 13, for more information on monitoring frequency and BSER determination. See sections VI.F.1.c and VI.F.2.b for discussion on the option to use Method 21 to monitor for fugitive emissions. We have also included language in the final rule that allows for the approval of emerging technologies for reducing fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 19

Comment: As an initial matter, the rule "find[s] that the cost of monitoring/repair based on quarterly monitoring at well sites using [optical gas imaging, or OGI] not cost-effective under either [the single- or multipollutant approach]." 80 *Fed. Reg.* at 56,636 (emphasis added). Given the inaccuracies in EPA's assessment of costs, as described in more detail herein, MarkWest agrees with this conclusion, and believes that if more accurate cost and benefit data were used, quarterly monitoring at well production facilities would be even more costly per ton of pollutant reduced (i.e., less cost-effective) than estimated in the proposal, and even semi-annual monitoring would be shown to be not cost-effective, as well.

With respect to monitoring frequency at compressor stations, MarkWest agrees with EPA that quarterly surveys would be problematic for many operators, significantly less cost effective, and should not be required under the rule if finalized. With respect to EPA's proposed requirement of semi-annual monitoring surveys at compressor stations, we again note that the data relied upon by EPA is quite dated and likely overestimates fugitive emissions, thus skewing the evaluation of semi-annual monitoring frequency with inflated emission reduction benefits that will not continue after the first or second survey. MarkWest therefore favors annual monitoring surveys as the most cost effective, and this approach would also avoid the very significant component tracking and recordkeeping burden associated with the proposed percentage-based "step-up" and "step-down" in monitoring frequency, addressed below.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 13, for more information on monitoring frequency and BSER determination. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 12

Comment: If fugitive monitoring is required, as proposed on page 56595, column 3, under Section B. Summary of the Major Provisions of the Regulatory Action, schedules of fugitive monitoring should be limited to annually after the initial survey due to the remote nature of many well sites and compressors.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 13, for more information on monitoring frequency and BSER determination.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 22

Comment: Instead of the current approach, we propose EPA require annual surveys, not to exceed one year between monitoring events. Based on the nature of operations in our segment of the industry, we think this would be a more appropriate interval for these surveys. Given that most of our compressor stations are unmanned, and frequently spread over a broad and difficult geographic area, performing surveys quarterly or even semi-annually would place a serious burden on operators. In addition, the contract crews and materials needed to repair any detected leaks may not be readily available in many of these remote areas. We would also have to coordinate between multiple contract crews, as the team repairing the equipment is unlikely to be the same group of people as the team monitoring leaks. As a result, many companies like ours would struggle to keep up with more frequent monitoring requirements. We believe that annual surveys will be adequate to ensure that leaks that might otherwise go unnoticed in auditory and visual inspections are discovered and corrected in a timely manner.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 13, for more information on monitoring frequency and BSER determination. We have taken into account the unique nature of this sector in regards to performing repairs, and as such, we have extended the allowable timeframe for making repairs. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more information on this issue. Additionally, we received a number of comments that indicated many components can be repaired on site during the monitoring survey with a simple tightening of screwed connections or replacement of small components carried by the maintenance team, in which case, the component can be resurveyed immediately. We acknowledge that this may take some coordination on a source's part, particularly if the monitoring survey is contracted, but we believe both economic and environmental benefits are realized from the coordination. However, if the maintenance personnel cannot be onsite at the time of the survey, there is a 30-day window following the monitoring survey for making repairs.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 10

Comment: Hess does not support fugitive emissions surveys more frequently than annually. In addition to costs to obtain leak detection equipment and train qualified personnel to conduct the surveys, operators will also incur significant expenses in cost and time associated with traveling to and from sites, vehicle and fuel costs, and resulting vehicle emissions to conduct recurring fugitive emissions surveys at all new or modified well sites or compressor stations. Crude oil and natural gas production operations, gathering and boosting facilities, and storage and compressor stations are necessarily geographically dispersed - often over hundreds of square miles. In North Dakota, Hess estimates that including drive time, it will take a minimum of three hours to conduct a thorough fugitive emissions survey of a single-well production site. Central facilities and multi-well pads could take several hours more. In 2014 alone, Hess drilled more than 230 wells in the Bakken. If the proposed fugitive emissions survey program for well sites had been in effect, it would have required a minimum of more than 700 man-hours just to conduct the initial fugitive emissions survey for those new sites. While Hess' drilling program has been reduced in response to current commodity prices, Hess expects to resume additional drilling as prices recover, and similar numbers of new wells could be drilled in future years. Moreover, new wells will continue to need to be surveyed in addition to all of the other wells drilled after the proposed rule goes into effect. Within just a few years, Hess could be required conduct fugitive emissions surveys at 500 or more sites, at a minimum cost of 3,000 man hours per year under the Proposed OOOOa Rule (even assuming follow-up well site visits are not required).

Given the sheer number of fugitive emissions surveys potentially required, Hess would be forced to conduct surveys year-round, potentially exposing workers to health and safety threats posed by the harsh North Dakota winter weather where blizzards and "white out" conditions and sub-zero temperatures are not uncommon. Semi-annual and quarterly monitoring could simply be impossible in some areas.

After the initial and first annual survey, operators should be allowed three years between follow-up emissions surveys. After a well site or compressor has been installed and verified by fugitive emissions survey to be leak-free, it is unlikely that substantial new leaks will develop during ordinary operating conditions. Moreover, unlike in a refinery or other manufacturing operation where production remains relatively steady year after year, after the initial couple of years of production, the emissions from well sites decrease dramatically due simply to the falloff in oil and gas production from the well. This reduction in production volumes directly correlates to reduced fugitive emissions. Allowing additional time between fugitive emissions surveys for low-producing wells will mitigate costs and safety hazards incurred to conduct unnecessary fugitive emissions surveys which are unlikely identify new fugitive emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6922, Excerpt 13, for more information on monitoring frequency and BSER determination. We understand that the implementation of a fugitive monitoring and repair program may find more leaks at the beginning of the program due to improper installation or defective equipment or components. However, data from leak programs show that after the initial survey, leaks reoccur at components that were repaired, in addition to new leaks that form due activities such as the wearing down of valve packing or improperly reseated PRDs. The monitoring and repair programs are intended to limit the emissions from these reoccurring and new leaks through periodic monitoring. We do not agree that three years between surveys is a reasonable time frame to accomplish emissions reductions. We also have no data supporting that the level of fugitive emissions directly correlate with a decline in production from the well. See section 4 of the TSD for further discussion.

Additionally, in the final rule we have added a waiver provision for fugitive emissions monitoring at compressor stations located in certain areas of the country where average temperatures are subzero for an extended period of time. The waiver applies for only one quarter per year and is not extended to well sites, as we do not know of any areas where temperatures are subzero for six months at a time. Therefore, we believe that owners and operators should be able to meet the monitoring requirements through careful planning. See section VI.F.2.a of the preamble to the final rule for more information on this issue.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 15

Comment: Frequency of survey requires flexibility

Annual survey or alternatively, phase in period preferred over proposed semi-annual frequency

First and foremost, in regard to the semi-annual survey frequency proposed aside from the fluctuations proposed based on number of components leaking that may follow, in and of itself will be difficult to manage for a large asset areas such as Pioneer's Permian Basin. As new wells and associated facilities are rapidly being drilled and constructed, and new wells are triggering modifications of existing production facilities, it will be a challenge for Pioneer to achieve the time and manpower required for our field staff to adequately survey each new site twice a year, in addition to the initial survey which may amount to three times a year to start. Consistent with TXOGA and Western Energy Alliance's comments, Pioneer suggests an annual survey frequency would be reasonable.

However, if EPA finalizes the semi-annual frequency, Pioneer strongly urges EPA to allow LDAR provisions in the final rule be phased in over a period of time, such as a year, to provide operators the necessary time to hire additional staff to conduct the monitoring, and to allow time for the field staff in charge of implementing the LDAR program in the field to be trained since training and certification is required in order to use OGI. It is vital that operators are allowed adequate time to comply with an extensive LDAR program such as that proposed in this rule so as to avoid an "out of compliance" lag period of time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4, for a discussion on phasing in the initial monitoring survey.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.

Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 52

Comment: EPA proposes as its primary proposal that leak detection surveys should be conducted semiannually. As described in Section V(E), above Kinder Morgan proposes that surveys be conducted annually for both well sites and compressor stations—a frequency consistent with Subpart W requirements in place for many of these facilities at this time.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 9

Comment: EPA has not justified why a departure from annual leak detection surveys, consistent with Part 98, Subpart W reporting, is inadequate.

INGAA recommends that fugitive emissions program surveys be required annually, which is consistent with EPA's survey schedule for sources subject to Subpart W of the GHGRP. There is no indication that a more aggressive schedule provides any meaningful environmental benefit in regard to GHG impacts. Over time, EPA's GHGRP data will show whether associated emissions are reasonably stable or declining. In addition, the component count tracking adds an unnecessary burden that should be eliminated. If EPA retains the performance-based schedules in the final rule, INGAA recommends flexibility allowing operators to forgo component count tracking and implementation of the more rigorous reporting schedule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for more information on monitoring frequency determination. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6882, Excerpt 27, regarding overlap between subpart OOOOa and subpart W.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 10

Comment: Instead, AGA recommends that EPA adopt an annual survey requirement. This is consistent with the survey schedule for sources subject to Subpart W of the GHGRP. There is no indication that a more aggressive schedule provides meaningful environmental benefit in regard to GHG impacts, so consistency with Subpart W is desirable. Over time, GHGRP data will show whether adjustments are necessary. However, if EPA retains the performance-based schedules, operators should be allowed to allow forgo component count tracking and implement the more rigorous schedule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for more information on monitoring frequency determination. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6882, Excerpt 27, regarding overlap between subpart OOOOa and subpart W.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 24

Comment: AGA Urges EPA To Consider Revisions That Promote Consistency With Other EPA Programs.

AGA appreciates EPA's attempt to minimize the burden on regulated parties by seeking comment on how the Agency can avoid duplication or conflicts with other existing regulations. Several examples are discussed in these comments (e.g., delay of repair provisions), and reiterated below.

The proposed rule requires semi-annual fugitive emission leak detection surveys at compressor stations. Instead, for consistency with EPA's Subpart W, the leak detection surveys should be required on an annual basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for more information on monitoring frequency determination. See response to DCN EPA-HQ-OAR-2010-0505-6882, Excerpt 27, regarding overlap between subpart OOOOa and subpart W.

Commenter Name: Pamela Lacey, Chief Regulatory Counsel
Commenter Affiliation: American Gas Association (AGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6936
Comment Excerpt Number: 9

Comment: The leak survey schedule should be annual and 180 days should be allowed for the initial survey.

EPA's proposal would include a performance based survey frequency that would depend on the scope of leaks – the frequency would vary from quarterly to annually depending on the percentage of components from which fugitive emissions were detected. Requiring operators to conduct a component count to assess the percentage of leaking components would add an unnecessary burden for minimal benefit.

Instead, AGA recommends that EPA adopt an annual survey requirement. This is consistent with the survey schedule for sources subject to Subpart W of the GHGRP. There is no indication that a more aggressive schedule provides meaningful environmental benefit in regard to GHG impacts, so consistency with Subpart W is desirable. Over time, GHGRP data will show whether adjustments are necessary. However, if EPA retains the performance-based schedules, operators should be allowed to allow forgo component count tracking and implement the more rigorous schedule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6882, Excerpt 27, regarding overlap between subpart OOOOa and subpart W. See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4, for a discussion on phasing in the initial monitoring survey.

Commenter Name: John W. Mitchell
Commenter Affiliation: Kansas Department of Health and Environment (KDHE)
Document Control Number: EPA-HQ-OAR-2010-0505-6804
Comment Excerpt Number: 4

Comment: Additionally, EPA is requiring annual leak checks at each site. These requirements would place additional regulatory burdens on the oil and gas industry yet will yield only small reductions in methane emissions relative to other VOC regulatory rules in place. KDHE suggests greater flexibility in these requirements that would still yield emission reductions. Specifically, KDHE suggests that after a site has been evaluated and determined to be below leak thresholds, the monitoring requirements should be reduced from annual to once every two years.

Response: The proposed rule required semi-annual monitoring for well sites and compressor stations. After review of comments and additional evaluation of model plants and costs, the final rule requires semi-annual monitoring for well sites and quarterly monitoring for compressor stations. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: I. Snow
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-5411
Comment Excerpt Number: 5

Comment: Finally, I support the section on monitoring fugitive emissions and the deadlines for repair. However, I think the survey frequency for fugitive emissions should begin at quarter annual intervals rather than semi-annual. Because there is ability for a source to change status and move down to semi-annual surveys, it would not be impossible for a firm to afford this amendment. It is simply a stronger initial incentive for the producer to get repairs right, rather than drag out the process, all the while emissions are escaping.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Cyrus Reed, Conservation Director
Commenter Affiliation: Lone Star Chapter, Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-5418
Comment Excerpt Number: 6

Comment: One key way in which EPA's proposal could better control methane emissions would be to require much broader and more specific leak detection and repair (LDAR) program. We know that Texas facilities have problems with equipment leaks because citizens have experienced them first hand, and Texas lacks even the most basic LDAR requirements for in-state facilities. We suggest monthly - or, at a minimum, quarterly-- required inspections, and the frequency of these surveys should remain constant, rather than variable. EPA's proposal would allow operators to reduce the frequency of inspections in the future if they find that the percentage of leaking equipment falls below certain thresholds. This would encourage bad operators to ignore or overlook leaks in order to qualify for less frequent inspections. EPA must remove this perverse incentive from the final rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 36

Comment: In respect of adequate and sufficient requirements for public health and safety, we recommend that all super emitters are mandated with quarterly monitoring surveys.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. The EPA notes that "super emitters" can change over time, such that finding them can be a moving target. We believe the best approach for finding "super emitters" is through a frequent monitoring program. Not only will the frequent monitoring program find these “super emitters”, it will also prevent other smaller leaks from becoming “super emitters”.

Commenter Name: Robert M. Gould
Commenter Affiliation: San Francisco Bay Area Physicians for Social Responsibility (SF Bay PSR)
Document Control Number: EPA-HQ-OAR-2010-0505-6819
Comment Excerpt Number: 8, 9

Comment: Strengthen the standards for leak repair. EPA must issue standards that require inspections frequently enough to protect the health of local communities – at least monthly or quarterly – and which should remain at a fixed frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: David M. Babson
Commenter Affiliation: Union of Concerned Scientists (UCS)
Document Control Number: EPA-HQ-OAR-2010-0505-6858
Comment Excerpt Number: 3

Comment: It is important that EPA is proposing methane leak detection and repair standards for both well sites and compressors, but there are three major concerns with the compliance requirements. First, methane inspections by operators would occur too infrequently, second, the proposal outlines provisions that would allow obligated parties to skip regular surveys if they report finding relatively few leaks at their sites, and third, the proposal would allow oil and gas operators up to six months to repair leaking equipment if the operators deem the fix “unsafe” within 15 days of discovery.

EPA needs to finalize standards that require inspections with a prescribed frequency (at least quarterly) in order to ensure that new leaks are identified and addressed on a regular and timely basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8, regarding delay of repair provisions. We do not believe it is prudent to force operators to immediately repair components that would expose personnel to immediate danger. We believe that these repair should be performed when the well or compressor is shutdown or the immediate danger is otherwise removed.

Commenter Name: Camilla Feibelman
Commenter Affiliation: Rio Grande Chapter of the Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-6895
Comment Excerpt Number: 7

Comment: One key way in which EPA's proposal could better control methane emissions would be to require much broader and more specific leak detection and repair (LDAR) program. We know that New Mexico facilities have problems with equipment leaks because citizens have experienced them first hand, and New Mexico lacks even the most basic LDAR requirements for in-state facilities. We suggest monthly – or, at a minimum, quarterly-- required inspections, and the frequency of these surveys should remain constant, rather than variable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 132

Comment: Leak detection and repair, we think that's one of the most important things you can do. We would suggest monthly or, at a minimum, quarterly required inspections, and we don't think those should be reduced over time. We think those should be constant, and we think those programs will pay for itself. It's way too long to allow industry up to six months to repair leaks. We need a more reasonable time to repair these leaks.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. With respect to time for repairs, see sections VI.F.1.e and VI.F.2.d of the preamble to the final rule. See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8, regarding delay of repair provisions.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 192

Comment: And I guess the last comment I would ask is also, you know, just to require the inspections are not done on a semiannual basis, but at least quarterly and that the system, the way it currently is set up, would incentivize operators to ignore or overlook leaks in order to qualify for the schedule of less frequent inspections that they currently would be set up to do and instead have it be required at all points.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 199

Comment: Inspections should be fixed and quarterly with mandatory reporting to EPA.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6887, Excerpt 3, for a discussion of recordkeeping and reporting. The EPA is requiring annual reports to be submitted electronically to the agency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 86

Comment: However, we hope EPA will improve the final rule by requiring owners and operators to frequently inspect their facilities either on a monthly or a quarterly schedule with no step-up or -down provisions based on the number of leaks they find.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 112

Comment: I also second that we should have more fixed inspections. They should be monthly or quarterly, rather than biannually.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 187

Comment: Frequent leak detection and repair inspections are the only way to catch and fix this problem, but the proposed EPA standards only call for monitoring twice a year, with opportunities for facilities to reduce the frequency of monitoring even further. This is not good enough. We urge EPA to finalize an LDAR program that calls for at least quarterly monitoring and is not subject to frequency adjustments.

States like Colorado and Wyoming are leading -- and leading companies have recognized that more frequent monitoring is necessary and cost effective. And they've employed these solutions in a commonsense way to help protect air quality and is consistent with economic development.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 203

Comment: The approach to leak detection and repair monitoring is also a concern; it is an open invitation to industry abuse. Owners and operators are incentivized to lowball the leaks that they find, in the way that the rule is structured, to avoid more frequent inspections. EPA should replace this trust-based approach with regular inspections, scheduled on at least a quarterly basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 16

Comment: Second, EPA must strengthen the standards for leak repair. While we are pleased to see methane-based leak suppression and repair standards proposed for well sites and compressor stations, the proposal lets operators go too long between inspections and has counterproductive provisions that would allow oil and gas companies to skip these surveys if they report findings relatively (inaudible). The final goal should require inspections often enough to protect local communities monthly or quarterly with straightforward, fixed frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Patrick Von Bargen, Executive Director
Commenter Affiliation: Center for Methane Emissions Solutions (CMES)
Document Control Number: EPA-HQ-OAR-2010-0505-6980
Comment Excerpt Number: 4

Comment: But CMES focuses its comments here on some over-arching themes that relate to the provisions of the rule in Section VII-G regarding "Fugitive Emissions from Well Sites and Compressor Stations," and the proposed rule's structure for the frequency or inspections.

Our comments are underwritten by several factual premises. First, leaks are caused both by equipment failure and by operator error. In an exhaustive study of super-emitting leaks in the Barnett Shale region, the authors concluded that "equipment malfunctions and error-inducing workforce conditions are the most common causes of excess emissions related to avoidable operating conditions." (Daniel Zavala-Araiza et al., "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," Environmental Science & Technology, page 8172.) Thus, leaks cannot be predicted based on the age or quality of the equipment, as operator error can render such equipment ineffective.

Second, while most of the leaks that occur are small, a minority of leaks are "super-emitters," accounting for a disproportionate amount of methane emissions that could be avoided. A few leaks can account for 20% of the methane emissions in a particular region. (See David R. Lyon et al. "Constructing a Spatially Resolved a Methane Emission Inventory for the Barnett Shale Region," Environmental Science & Technology, pages 8147-8155.) Because methane leaks cannot be seen or smelled by oil and gas workers, even these large super-emitting leaks can go completely undetected.

Third, once detected, it is almost always economic for the producer to repair these leaks. Such was the conclusion of a Carbon Limits study of data from 4,293 surveys of oil and gas facilities in the U.S. and Canada published in 2014:

"The vast majority of leaks are economic to repair once identified: even assuming a low value of gas (3 USD per McF), leaks amounting to more than 97% of total leak emissions are worth repairing. In addition, over 90% are from leaks that can be repaired with a payback period of less than one year. This means that once the survey has been performed, it is economic to repair almost every leak, even at low gas prices." (Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras, Carbon Limits Report CL-13-27, March of 2014, page 5.)

These factual premises lead to the following conclusions regarding the proposed rule.

1. The EPA should require quarterly inspections of covered facilities, because:
a. super-emitters contribute disproportionally to methane emissions in any particular region;
b. without inspection an oil and gas producer cannot determine whether there exists a small or super-emitting leak;
c. such super-emitting leaks can be just as easily be produced by operator error as by an equipment failure;
d. the amount of methane released into the atmosphere by a super-emitting leaks can be enormous if such a leak goes undetected for up to six months;
e. quarterly inspections result in methane emissions reductions 50% higher than the reductions produced by annual inspections (See Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, ICF International, page 3-10);
f. the net present value of quarterly inspections (taking into account the natural gas not wasted if repaired quickly) is either neutral or, at worst case, only slightly negative (see Carbon Limits study, page 7); and that quarterly inspections are either not a significant burden on oil and gas producers or a net positive, with early paybacks from recovering the otherwise waste natural gas.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 26

Comment: Most of the leaks are caused by a very small portion of components, .13 -- .13 percent. One of the critical things that we'd like addressed is the –

We'd like the frequency of inspections at a quarterly rate.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 43

Comment: While we credit the EPA with their initial proposal for leak detection inspections, the step up and down provisions based on a number of leaky components is based on faulty logic.

Studies have shown that leaks by nature are random and thus make comprehensive and frequent inspections critical. Emerging data shows that a disproportionate share of fugitive emissions can come from a relatively small percentage of leaks and that these can appear almost anywhere at any time.

More frequent intervals such as monthly or quarterly inspections is what is needed and can be just as cost effective. Stepping up the frequency of inspections allows for better identification and fixing of leaks which will greatly impact the overall reduction of methane.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 82

Comment: Two, we urge the EPA to strengthen the leak detection and repair provision. The proposed standards call for semiannual LDAR monitoring with opportunities for facilities to reduce the frequency of monitoring even further. But a common finding of EPA methane studies is that a relatively small number of high emitting components and sites contribute a large fraction to the total emissions. Frequent LDAR to find and fix these leaks is critical to mitigating methane emissions as leaks can emerge anywhere at any time and can be difficult to predict.

States like Colorado and Wyoming have recognized that more frequent monitoring is necessary and cost-effective, and accordingly, we urge the EPA to finalize a program that requires quarterly monitoring -- monitoring and is not subject to frequency adjusting based on a facility's percentage of leaking components.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 123

Comment: Two, EDF strongly urges EPA to strengthen leak detection and repair provisions. The proposed standards call for semi-annual LDAR monitoring with opportunities for facilities to reduce the frequency of monitoring even further.

There is a common finding among dozens of scientific studies that a relatively small number of high-emitting components and sites are responsible for a large fraction of total methane emissions from the natural gas supply chain. Frequent LDAR to find and fix these leaks is essential to effectively reducing methane emissions. These large leaks can emerge anywhere at any time and are difficult to predict when and where they will occur a priori.

States like Colorado and Wyoming have recognized that more frequent monitoring is necessary and cost-effective. Accordingly, we urge EPA to finalize an LDAR program that requires at least quarterly monitoring and is not subject to adjustment based on a facility's percentage of leaking components.

There's no data to suggest that the absence of leaks in a single facility over some period is a good predictor of the probability of a leak developing in the future.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Colorado Latino Community Members to Senator Bennet
Commenter Affiliation: Colorado Latino Community Members
Document Control Number: EPA-HQ-OAR-2010-0505-5680
Comment Excerpt Number: 2

Comment: But unfortunately, while EPA's proposal is a critical first step, it falls short of the Colorado model in a few key details- such as requiring leak inspections at sites on at least a quarterly basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 4

Comment: Under the NSPS proposal, leak detection and repair (LDAR) surveys would be conducted semi-annually or annually, depending on the percent of the fugitive emission components during a survey. The DEP recommends that EPA require quarterly LDAR surveys to reduce VOC and methane emissions, as required under the DEP General Plan Approval/General Operating Permit for Natural Gas Compression and/or Processing Facilities (GP-5 or General Permit).

Within 180 calendar days after the initial startup of a source, the owner or operator of the facility must, at a minimum on a quarterly basis, use forward looking infrared (FLIR) cameras or other leak detection monitoring devices approved by the DEP for the detection of fugitive leaks. GP-5 further provides that the DEP may grant an extension for use of a FLIR camera upon receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension. Since the issuance of GP-5 in 2013, the DEP has issued 510 authorizations to use the General Permit. The DEP urges the EPA to adopt LDAR provisions at least as stringent as the requirements being implemented in the Commonwealth for the oil and natural gas sector.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 28

Comment: EPA has acknowledged that although Pennsylvania has a General Permit which specifies quarterly monitoring at a compressor station, EPA believes that quarterly monitoring could cause a burden on small businesses in the United States and many operators would need to hire contractors due to the cost of the specialized equipment needed to perform the monitoring survey and the training necessary to properly operate the equipment whether OGI or Method 21 is used. For that reason, EPA recommends that RACT for this sector is semiannual monitoring at well sites and gathering and boosting compressor stations.

The DEP's GP-5, in effect since February 1, 2013, requires source owners and operators to comply with stringent requirements including an LDAR program for any type of leak. LDAR surveys must be conducted on a quarterly basis. The quarterly LDAR program for sources at natural gas compression and processing facilities in Pennsylvania has been implemented successfully for more than two years. To this end, DEP urges that EPA's final rule require LDAR surveys to be performed on a quarterly basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination.

Commenter Name: Patricia Karr Seabrook
Commenter Affiliation: Miller/Howard Investments, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6818
Comment Excerpt Number: 3

Comment: We welcome the methane-based leak detection and repair standards proposed for well sites and compressor stations, but we think they need to be more frequent than once a year. The regulations developed in Colorado, with industry cooperation, call for quarterly inspections.

This seems to be a cost-effective approach that is not unduly burdensome, and we recommend that the federal regulations adopt a similar schedule. We are concerned that super-emitters could be overlooked for a considerable period if there is not a more regular schedule of leak detection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. We agree that the best approach for finding "super emitters" is through a frequent monitoring program.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 11

Comment: Quarterly OGI LDAR

The Division supports quarterly leak monitoring for some facilities, or allowing an adequate state program as an alternative to NSPS OOOOa LDAR. EPA determined that quarterly OGI monitoring of fugitive emissions components at well sites may not be cost-effective for some facilities. EPA also determined that OGI monitoring costs for compressor stations are comparable at an annual, semiannual, or quarterly monitoring frequency. The Division believes that quarterly, and even monthly, inspections can be cost-effective for larger emitting well sites and compressor stations.

Colorado established a cost-effective LDAR program for well production facilities and natural gas compressor stations that bases the inspection frequency on facility emissions. This tiered approach addressed cost, equipment, and staffing concerns for some operators. Natural gas compressor stations must inspect components annually, quarterly, or monthly, based on the facility's fugitive VOC emissions. Well production facilities must inspect components once, annually, quarterly, or monthly, based on the facility's highest emitting storage tank emissions, or facility emissions if the facility does not have storage tanks. Most well production facilities must also conduct monthly AVO inspections. As discussed in Colorado's economic impact analyses, Colorado has determined that these inspection frequencies are cost-effective.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. We agree with the commenter that more frequent monitoring can be cost-effective for lager facilities, however, the EPA has based these monitoring frequency requirements on an average sized facility based on available nationwide data. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.

Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 47

Comment: State regulators have established that frequent LDAR is feasible and cost-effective. Currently, five major oil and natural gas producing states require quarterly monitoring at oil and gas facilities—Colorado, Ohio, Pennsylvania, Wyoming and Utah. California has also proposed LDAR standards at new and existing sources statewide that, if adopted, would require quarterly LDAR using OGI instruments. In addition, four air districts in Southern California already have existing inspection and maintenance requirements aimed at detecting non-methane hydrocarbon leaks, each requiring quarterly inspections as a baseline.

Colorado has adopted comprehensive LDAR requirements to reduce hydrocarbon leaks—consisting of methane as well as other organic compounds— at compressor stations, well sites, and storage tank batteries. Colorado's rule includes tiered frequency requirements based on the potential to emit VOCs, including inspection frequencies ranging from one time at the smallest facilities to monthly at the largest facilities. Mid-sized facilities are required to undertake inspections on a quarterly basis. 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb.24, 2014). As a weighted average across all facilities, Colorado determined that its approach resulted in approximately 4.7 inspections per year. Colorado's rule demonstrated the cost- effectiveness of quarterly inspections: for mid-sized compressor stations, the abatement cost was calculated at $746/metric ton of methane, and for well site inspections, the cost was $831/metric ton of methane. As a whole, Colorado's tiered inspection frequency was likewise highly cost- effective, achieving emission reductions estimated at $1,259/ ton of VOC and $805/ton of methane/ethane at well sites and $994/ton of VOCs and $474/ton of methane/ethane at compressor stations.

Other states have similarly adopted programs with quarterly monitoring requirements:

- Wyoming. Wyoming requires quarterly instrument-based inspections at all new and modified well sites in its Upper Green River Basin with the potential to emit four tons of volatile organic compounds from fugitive components. The state recently finalized the same requirements for existing well sites and compressor stations in the Basin. Comments submitted in support of these requirements suggest that these requirements are highly cost-effective.
- Ohio. Ohio requires quarterly inspections for leaks at unconventional well sites, using either a FLIR camera or Method 21 compliant analyzer.
- Pennsylvania. Pennsylvania requires quarterly inspections of all onshore gas processing plants and compressor stations in the gathering and boosting sector. Like Colorado, Pennsylvania requires that operators inspect for and repair methane leaks as well as VOC leaks. Pennsylvania requires operators to utilize either a FLIR camera or "other leak detection monitoring devices approved by the Department."
- Utah. Utah requires quarterly inspections at well sites and storage tank batteries using an IR camera, Method 21, or tunable laser absorption spectroscopy.

Furthermore, Pennsylvania, Wyoming, and Colorado do not allow operators to adjust the frequency of inspection based about the reported survey results, as EPA has proposed.

EPA Should Strengthen Frequency Requirements in the Final Rule.

In summary, EPA should strengthen frequency requirements in two important respects:

- Strengthen baseline monitoring frequency. As described above, there is substantial evidence supporting the cost-effectiveness of quarterly monitoring programs, and EPA should strengthen the frequency of inspection by requiring quarterly monitoring for affected facilities. At the same time, we recognize an approach based on a single model facility necessarily fails to capture substantial variation among facilities. Indeed, EPA's own model well analysis reflects this substantial variation among basins, with average wells per pad ranging from one to 13. Accordingly, if EPA does not finalize a quarterly requirement, we recommend a tiered approach to monitoring frequency similar to Colorado's. Such an approach would optimize monitoring requirements based on facility size and complexity.
- Remove step-down provisions. In addition, EPA's proposed step-down provisions, which allow frequency adjustments based on the percentage of leaking components, are arbitrary, unrelated to emissions performance, and should be removed from the final standards.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination.

Commenter Name: Interfaith Center on Corporate Responsibility (ICCR)
Commenter Affiliation: Interfaith Center on Corporate Responsibility (ICCR)
Document Control Number: EPA-HQ-OAR-2010-0505-7068
Comment Excerpt Number: 6

Comment: We welcome the methane-based leak detection and repair standards proposed for well sites and compressor stations, but we think they need to be more frequent than once a year. The regulations developed in Colorado, with industry cooperation, call for quarterly inspections. This seems to be a cost-effective approach that is not unduly burdensome, and we recommend that the federal regulations adopt a similar schedule. We are concerned that super-emitters could be overlooked for a considerable period if there is not a more regular schedule of leak detection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. We agree that the best approach for finding "super emitters" is through a frequent monitoring program. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 154

Comment: EPA is proposing that the first attempt repairing leaks occur within five calendar days after the leak is detected. Repair of the leak would be completed no later than 15 days after detection of fugitive emissions.

The PA DEP strongly recommends strong leak detection and repair requirements and is currently evaluating stronger state specific LDAR requirements.

Under the NSPS proposal, LDAR surveys would be conducted semi-annually or annually. Consistent with the Department's GP-5 requirements, LDAR surveys should be performed on a quarterly basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6859, Excerpt 15, for a discussion on existing programs based on state requirements and coordination. With respect to time for repairs, see sections VI.F.1.e and VI.F.2.d of the preamble to the final rule.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 11

Comment: We recommend OGI monitoring surveys on a quarterly basis for new and modified well sites, for all well sites, compressor and dehydration stations. Our knowledge, based on our experiences living in the gas fields has shown that methane will vent either from a relief valve mechanism designed for safety purposes or from another point on the well pad, compressor or dehydration station. These releases are not always indicated on the operator's SCADA. When nearby residents' phone 9-1-1 to report a release, generally the operator will take action. It is important to note that besides ordinary fugitive emissions, SCADA does not always reveal a malfunction, at times problems occur, and releases happen on such a schedule they are not considered uncommon; thus adopting quarterly OGI monitoring surveys will reduce reportable fugitive emissions and those that go unreported as well.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 12

Comment: Additionally, according to an economic analysis conducted by ICF International (ICF) for the Environmental Defense Fund in March 2014, more frequent inspections result in greater emission reductions. The ICF report, which cites research conducted by EPA and Colorado, concludes that annual inspections will reduce emissions by 40 percent; quarterly inspections will reduce emissions by 60 percent and monthly inspections reduce emissions by 80 percent. ICF also estimates that the cost of reduction ($/Mcf methane reduced) for quarterly LDAR surveys ranges from $4.10 to $7.60 without gas credit. Based on these cost estimates and the implementation of DEP's existing LDAR program, quarterly LDAR survey requirements should be imposed nationally for the oil and natural gas sector. This cost-effective strategy would significantly reduce methane and VOC emissions including hazardous air pollutants.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 4

Comment: Quarterly Monitoring Using OGI is Cost Effective. EPA has underestimated the potential benefits and overestimated the costs of leak detection and repair (LDAR) requirements to reduce volatile organic compound (VOC) and methane emissions. If correctly estimated, these benefits and costs would demonstrate that quarterly monitoring using OGI is in fact cost effective. EPA has underestimated the potential benefits by:

- Underestimating the total amount of fugitive emissions released from this sector; and
- Failing to acknowledge that leak detection surveys will help reduce vented emissions from storage vessels released in violation of the standards.

Similarly, EPA has overestimated the costs of leak detection requirements because:

- Operators already own the necessary equipment;
- Operators do not need to buy separate equipment for each affected facility; and
- OGI contractors cost significantly less than EPA has estimated.

Although operators already own the necessary equipment and are conducting OGI surveys voluntarily in many instances, nationally applicable regulations are still necessary to help assure a level playing field across the industry and assure that fugitive emission reductions are enforceable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. We disagree with the commenter that all operators already own either an OGI instrument or Method 21 instrument. See section 4 of the TSD and the OGI Cost Memo[5] for more information related to the monitoring costs.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 45

Comment: States, Industry Experience, and Independent Assessment Suggests that Frequent LDAR is Cost-Effective.

Indeed, states, industry evaluations, and independent assessment have found quarterly (or more frequent) LDAR to be highly cost-effective, and have not adopted skip monitoring provisions. Table 6 below sets forth some of these estimates, all of which are several times lower than EPA's estimate for quarterly LDAR in the TSD. Figure 7 shows how EPA's estimate compares to these estimates.

[Table 6; Cost Effectiveness Estimates for Quarterly and More Frequent LDAR, summarizes State of CO, IFC study and Noble frequency, pollutant and cost-effectiveness at well sites, gathering compressor stations and transmission compressor stations].

Figure 7, below, illustrates the LDAR cost-effectiveness figures for quarterly LDAR per the 2015 proposed NSPS relative to the cost ranges for quarterly LDAR as calculated by various other sources. As shown, many of the costs assumed by the proposed standard are much higher than other estimates.

[Figure 7: EPA 2015 Proposed NSPS for Methane and VOC Cost-Effectiveness of LDAR for Fugitive Emissions from Equipment Leaks Compared to Other Estimates]

Frequent LDAR is supported by industry experience**.** Jonah Energy—an operator in the Upper Green River Basin in Wyoming— has expressed its support of at least quarterly instrument-based inspections, noting that it already complies with the proposal because "each month, Jonah Energy conducts infrared camera surveys using a forward-looking infrared camera ("FLIR") camera at each of our production facility locations." According to Jonah, "[b]ased on a market value of natural gas of $4/MMBtu, the estimated gas savings from the repair of leaks identified exceeded the labor and material cost of repairing the identified leaks" while also significantly

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[5] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA: Evaluation of Cost Methodologies for Optical Gas Imaging (OGI) Monitoring (April 6, 2016)

reducing pollution. Jonah's experience that gas savings from repairs often exceed the cost of performing repairs to identified leaks is also borne out by the Carbon Limits report and analysis carried out by Colorado.

In addition, several companies that engaged in the development of Colorado's regulations provided evidence that frequent LDAR is cost-effective. In particular, Noble estimated the cost-effectiveness of Colorado's tiered program at "between approximately $50/ton and $380/ton VOC removed" at well production facilities.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Robert LeResche, Chair
Commenter Affiliation: Western Organization of Resource Councils (WORC) et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6962
Comment Excerpt Number: 7

Comment: Increasing inspections and improving leak detection protocols. Requirements in the proposed rule related to inspecting sites to detect methane leaks should be strengthened to ensure that no leak goes unnoticed and unremediated. The proposed requirements of baseline equipment testing for leaks every six months, or every three months when a leak has been detected, allow too long between tests to determine unequivocally whether or not a given piece of equipment has leaks. We urge EPA to require quarterly inspections. Additionally, if a leak is detected during a routine inspection, the number of inspections should be increased to twice a month until no leaks are detected. Once no leaks are detected, inspections could switch back to once every quarter. With increased inspections there will be fewer time gaps during which leaks will go on unnoticed by operators and regulators.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Patrick Von Bargen, Executive Director
Commenter Affiliation: Center for Methane Emissions Solutions (CMES)
Document Control Number: EPA-HQ-OAR-2010-0505-6980
Comment Excerpt Number: 7

Comment: The costs and benefits to the producers and the net present value of greenhouse gas abatement under quarterly inspections should be evaluated and modeled over the first two years under the new rule. Should that evaluation compel a different inspection regime, the rule should be amended accordingly. But until that modeling and data analysis is complete, the EPA should avail itself of the benefits of the quarterly inspection regime which appears to have worked so well in Colorado.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 127

Comment: 27.4.2 Quarterly Monitoring for Super Emitters. Recognizing that additional data may be available, such as emissions from super emitters that may have higher emission factors than those considered in this analysis, EPA indicated that they are taking comment on requiring monitoring survey on a quarterly basis.

As indicated in Section 27.3.9, API finds that recurring LDAR has diminishing return.

Quarterly monitoring may not be possible in all areas. For example in some areas, particularly in western mountainous areas, winter weather makes it difficult to visit well sites that can be remote and widely scattered. It also may not be possible to utilize OGI methods in winter conditions, since visual detection of leaks requires a temperature difference between the leak and ambient air. Test data presented in Table 4-13 of EPA's draft Technical Support Document (TSD) *Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)* shows that 5,000 ppm leaks were detected with delta temperatures between the gas leak and background of around 1.4 to 1.9°C (2.5 to 3.4°F). However, the delta temperature is highly dependent on other factors, such as the wind conditions, hydrocarbon concentration, and mass emission rate.

In addition, even EPA's cost analysis found that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions. Per page 56636 of FR version, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach."

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. Additionally, in the final rule we have added a waiver provision for fugitive emissions monitoring at compressor stations located in certain areas of the country where average temperatures are subzero for an extended period of time. The waiver applies for only one quarter per year and is not extended to well sites, as we do not know of any areas where temperatures are subzero for six months at a time. Therefore, we believe that owners and operators should be able to meet the monitoring requirements through careful planning. See section VI.F.2.a of the preamble to the final rule for more information on this issue.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 35

Comment: While PIOGA supports performance based frequency of LDAR surveys, PIOGA does not support requiring LDAR surveys more frequently than semiannually under any circumstances. The added financial burden and limited environmental benefit of quarterly surveys do not support a higher frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: J. E. Rosenberg
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6887
Comment Excerpt Number: 7

Comment: Twice a year to perform LDAR checks using OGI is not often enough. The proposed rule should be amended to require checks at least quarterly.

As above, industry cannot claim that quarterly LDAR checks using OGI constitute an undue burden. The Bernville Compressor Station incident referred to above shows decisively that very substantial leaks can occur over very short time-frames. Ideally, compressor stations and unconventional Oil & Gas wells should be subjected to some form of 24 x 7 real-time monitoring. Technology for doing so is not yet practical at reasonable cost, however, but EPA must be vigilant for the emergence of such technology, and upgrade this rule as circumstances warrant. Meantime, the LDAR requirement must have the highest frequency practicable. Surely more frequent LDAR checks than twice a year are achievable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. The EPA has finalized a process for the agency to evaluate alternate or emerging technology. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Stuart A. Clark and Ursula Nelson, Co-President
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6932, EPA-HQ-OAR-2010-0505-6961
Comment Excerpt Number: 6, 7

Comment: *Leakage Reporting Frequency*

EPA specifically requested comment on the frequency of periodic site-wide surveys to detect VOC and methane leaks from equipment at natural gas well sites, oil well sites, natural gas production and boosting stations and natural gas transmission compressor stations. The agency has proposed that the surveys take place on an annual or semi-annual basis. On one hand, NACAA is concerned that a reporting and/or monitoring frequency that is too low will allow significant leaks to go undetected. But NACAA also recognizes that time and resource constraints limit states' ability to prepare reports and EPA's ability to review them. NACAA believes that a schedule where leak detection surveys are required on a quarterly basis, but where the results are only reported to EPA annually, strikes the right balance.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. Information on monitoring surveys is included in the annual report which is submitted to the agency electronically.

Commenter Name: Jonas Kron
Commenter Affiliation: Trillium Asset Management, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6794
Comment Excerpt Number: 3

Comment: While Trillium strongly supports the decision to include LDAR standards in the proposal we are concerned that the standard allows operators too much time between inspections. We believe the EPA should establish a standard that sets inspections at a monthly or quarterly interval – a rate that will provide the appropriate level of policy pressure on the industry to reduce methane emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Roy Rusty Bennett
Commenter Affiliation: Mehoopany Creek Watershed
Document Control Number: EPA-HQ-OAR-2010-0505-6816
Comment Excerpt Number: 5

Comment: We recommend surveys on a quarterly basis for new and modified well sites, for all well sites, compressor and dehydration stations. We recommend OGI monitoring surveys on a quarterly basis for new and modified well sites, for all well sites, compressor and dehydration stations. We recommend mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate- detection.

As priority is placed on the public who lives within the unconventional development area we recommend mandatory well site monitoring surveys at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection.

We recommend mandatory compressor station monitoring surveys at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection.

...

We recommend mandatory compressor station monitoring surveys at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection.

We recommend mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate- detection.

We advocate a straightforward approach to monitoring fugitive emissions at compressor stations. We recommend mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 24

Comment: And finally, I'd like them to require more frequent leak inspections, of at least four times a year, especially of compressor stations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 240

Comment: Second, EPA should strengthen standards for leak inspection. Performing inspections only semiannually is much too infrequent and inadequate; monthly or even quarterly inspections would be -- are more appropriate to identify and repair leaks in a timely manner.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 25

Comment: We also hope that more frequent and fixed leak detection and repair requirements will be included, and we recommend requiring these on a quarterly basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 12

Comment: Increased/decreased LDAR inspection frequency

EPA has proposed to allow or require decreased or increased leak inspections, based on the percentage of leaking fugitive emission components. The Division is concerned with the potential administrative burdens and compliance challenges of a "step up, step down" LDAR program.

In developing Colorado's LDAR program, the Division considered a "step down" inspection frequency based on the percentage of leaking components, but was concerned with potentially disincentivizing the detection and repair of leaks. The Division was also concerned with the potential burdens of tracking components for the purpose of a step down LDAR program. Either an owner or operator would have to track potentially thousands of components at each facility, or rely on component count studies such as the GRI/EPA document from 1996, which may no longer be the most accurate information due to changes in facility development. This concern about the potential burden associated with tracking components was generally supported by many industry stakeholders, particularly related to recordkeeping. The Division was also concerned with the accuracy of tracking components and the challenges of compliance oversight with a step down LDAR program, such as component count and detection verification. The Division supports proactive emission reduction activities and is open to approaches that incentivize and reward operators that implement highly effective LDAR programs. However, the Division notes that the percentage of leaks may be a misleading metric for a step down program. This is due to the potential for a facility to avoid LDAR activities when the facility does not have many leaks, according to percentage, but may in fact emit a large quantity of fugitive emissions from leaking components. The percentage of leaks may not be representative of the volume or rate of fugitive emissions, and, therefore, may not require the inspection and repair of "super emitters." Colorado ultimately decided not to include a step down inspection program in its 2014 regulations. The Division suggests EPA consider similar concerns when finalizing the NSPS OOOOa LDAR inspection frequencies, or allow an adequate state program as an alternative to NSPS OOOOa LDAR.

Response: We agree with the commenter that the provision for change in monitoring frequency presents potential disincentive for operators to conduct routine maintenance and also presents a significant associated burden of tracking components. Therefore, we have finalized the rule with fixed monitoring frequencies with no change due to leak rate performance. See sections VI.F.1.d and VI.F.2.c of the preamble to the final rule for a discussion on this issue.

Commenter Name: Dayle McDermitt, Vice President, Research and Development
Commenter Affiliation: LI-COR, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-5413
Comment Excerpt Number: 4

Comment: Optical imaging (OI) devices are adequate confirmation tools for identifying specific leak locations, once a potential leak has already been identified using a continuous monitoring method. However, the use of only optical imaging devices to search for leaks at time intervals that exceed 6 months - as stated in the standards - could allow fugitive emissions to vent to the atmosphere for many months to years.

Response: The EPA disagrees that when used appropriately optical gas imaging and Method 21 are not adequate leak detection tools absence continuous monitoring methods. We are finalizing requirements for owners and operators to perform fugitive emissions surveys quarterly for compressor stations and semiannually for well sites. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for information on a pathway for emerging technologies.

Commenter Name: Jonas Kron
Commenter Affiliation: Trillium Asset Management, LLC

Document Control Number: EPA-HQ-OAR-2010-0505-6794
Comment Excerpt Number: 5

Comment: We are also aware that studies suggest that a facility's leaking components percentage does not accurately predict its emissions level. Without reliable predictions of emissions levels, we are concerned that the proposed regulation would result in oil and gas companies being able to skip inspections based on the results of prior inspection. There may also be another unintended consequence of this ability to skip surveys: it may incentivize operators to ignore or overlook leaks.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Patricia Karr Seabrook
Commenter Affiliation: Miller/Howard Investments, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6818
Comment Excerpt Number: 4

Comment: We are particularly concerned about provisions in the rule that allow oil and gas companies to skip leak detection surveys when they report finding relatively few leaks at these sites. Recent studies show that a facility's percentage of leaking equipment is not an accurate predictor of its emissions. A company may have a small percentage of leaks, but they may be significant in size. Studies show that there is a high degree of unpredictability and randomness to leaks, with super-emitters resulting from human error, manufacturing defects, and/or wear and tear. Frequent, regular monitoring with leak detection equipment is necessary to prevent climate-related pollution and negative impact on the health of communities, as well as to reduce the loss of valuable product. We are also concerned that allowing oil and gas companies to skip inspections based on the results of prior inspections may incentivize them to ignore or overlook leaks so they can skip the next survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 154

Comment: Strengthen the standards for leak repair so that you get all fugitive emissions and don't skip any surveys;

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: David M. Babson
Commenter Affiliation: Union of Concerned Scientists (UCS)
Document Control Number: EPA-HQ-OAR-2010-0505-6858
Comment Excerpt Number: 4

Comment: Further, EPA offered no data to suggest that past survey performance accurately predicts current or future performance, and therefore, allowing oil and gas operations to skip inspections based on the results of prior inspections would not effectively reduce methane leaks. In fact, finalizing these provisions would ensure that new leaks are less likely to be identified and remain a problem longer than necessary.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876 excerpt 12.

Commenter Name: Colleen Cooley
Commenter Affiliation: Diné Citizens Against Ruining Our Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6883
Comment Excerpt Number: 3

Comment: Strengthen the standards for leak repair. We are pleased to see methane-based leak detection and repair standards proposed for well-sites and compressor stations. However, the approach EPA took in the proposed rule lets operators go too long between inspections, and has counterproductive provisions that allow oil and gas companies to skip these surveys when they report finding relatively few leaks at these sites. EPA needs to issue standards that require inspections often enough to protect local communities – monthly or quarterly – with straightforward, fixed frequency.

Recent science shows that a facility's percentage of leaking components does not accurately predict its emissions. Allowing oil and gas companies to skip inspections based on the results of prior inspections will not effectively reduce harmful leaks. To make matters worse, these "skip survey" programs incentivize oil and gas companies to ignore or overlook leaks so they can skip the next survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information regarding fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Andrew Casper
Commenter Affiliation: Colorado Oil & Gas Association (COGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6889
Comment Excerpt Number: 12

Comment: With respect to monitoring frequency, certain LDAR regimes favor a step-up/step-down frequency based upon the number of leaks found. While some Colorado operators initially favored this approach, it has become apparent that these incentives do not actually improve efficiency and, in fact, make the program significantly more burdensome, if not unmanageable. First, Colorado operators have indicated that coordination of inspections and subsequent recordkeeping duties already requires a significant amount of time and resources, without the added complication of having to manage an inspection schedule that constantly changes. Instead, Colorado operators support correlating LDAR inspection frequency with actual emissions because the inspection frequency will be more frequent at larger facilities that have a higher emissions potential (and thus a corresponding higher potential for fugitive emission leaks). This methodology allows inspection frequency to naturally decrease as emissions decrease without implementing a step-up/step-down frequency. In fact, an emissions-based frequency is preferable to a frequency based on the percentage of leaking components because—given the large and changing number of facility components—most operators do not conduct actual component counts at each well production facility and/or natural gas compressor station. Having to track the number of components and any additions and deletions that occur over time will add significant costs to manage the LDAR program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12. We believe that an emissions-based frequency is likewise burdensome for tracking components and therefore, have finalized a fixed monitoring frequency in the rule. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 15

Comment: While we appreciate the purpose behind an incentive-based LDAR program—one that rewards operators who follow diligent inspection and repair protocols—the proposed step-up/step-down approach is unworkable. The proposal requires operators to track the percentage of leaking components at every possible location; both to first establish a baseline, and then to track changes, modifications, and repairs. Tracking these components will require operators to use extraordinary software and database sets that are simply not realistic, practical, or cost-effective.

The proposed LDAR program is tantamount to similar LDAR requirements for gas plants. Unlike gas plants, however, well sites and compressor stations are typically unmanned and do not provide operators with easy access to spare parts for making repairs. It is unreasonable to expect a record of every valve, flange, and gasket across thousands—or, possibly tens of thousands—of wells and production facilities, and then to track changes to the same year-after-year. The data management burdens alone are not practical or reasonable. And this is to say nothing of the implementation burdens that would be required: including hiring crews; training on component identification; implementing a tagging program, etc. Small producers would be disproportionally affected, as they lack the IT management capabilities to develop and maintain such extensive databases. Moreover, the costly and complex undertaking of building and maintaining such a database imposes significant costs on operators and ultimately end-consumers, while providing no environmental benefit. States such as Colorado, Wyoming, and Utah already achieve similar, if not greater, environmental benefits than promised under the proposal. But these states do so without the logistical challenges of a percentage-based approach. We strongly recommend the rule not include a program provision that would require extensive data management (i.e., no step-up/step-down provision).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Cory Hansen, et al.
Commenter Affiliation: Institute for Policy Integrity at New York University School of Law
Document Control Number: EPA-HQ-OAR-2010-0505-6931
Comment Excerpt Number: 10

Comment: The Proposed Rule's sliding schedule could also have the undesirable effect of turning attention away from components as they age. As components age, they become more likely to leak, making the need for inspection and repair greater. By decreasing inspection frequency based on past performance, older equipment will be inspected less. Furthermore, there is evidence that natural gas leaks are random events. Components that leaked in the past may not leak again, and components that have never leaked may do so in the future. Large leaks have been found to be particularly episodic, as they may result from maintenance and equipment malfunction or deterioration. In short, EPA may risk more frequent leaks by ratcheting down inspection schedules over time.

Thus, there are several additional factors that EPA could have considered in its benefit-cost analysis with respect to OGI frequency, including but not limited to: the effects of aging equipment on leak frequency and magnitude; the price and availability of OGI technology for purchase; the cost of repeated inspections; the episodic nature of large leaks; and potential technological advancement of OGI technology and its effect on price. Ideally, EPA should use cost-benefit analysis to determine the socially optimal level of OGI frequency. And regardless of how stringently EPA sets OGI frequency rates now, EPA should plan to gather information about compliance cost and inspection efficacy on an ongoing basis, and schedule retrospective review to fine-tune OGI frequency requirements in the future.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

The EPA monitors the effectiveness of rule requirements and compliance strategies and will continue to evaluate these requirements in the future.

Commenter Name/Affiliation: Stuart A. Clark and Ursula Nelson, Co-President / National Association of Clean Air Agencies (NACAA)
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6932 / Excerpt Number 7

Commenter Name/Affiliation: Stuart A. Clark (Washington), Co-President and Ursula Nelson (Pima County, AZ), Co-President / National Association of Clean Air Agencies (NACAA)
Commenter Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6961 / Excerpt Number 7

Comment: NACAA also encourages EPA to revise the proposed incentive structure that would allow states to lower their survey obligations. The proposed NSPS allows owner/operators to reduce the monitoring survey frequency if leaks are found at only a small percentage of covered components. For example, if leaks are found at less than one percent of covered components during two consecutive surveys, the survey frequency decreases. We have identified two concerns with this approach. First, an incentive based solely on the number of leaks detected may encourage some owner/operators to underestimate the amount of leakage at their facilities during surveys. Second, the percentage-based metric, which requires a baseline count of total covered components, may be difficult to implement. The large number of components involved and significant variations in the types of components deployed across different categories of sites may create a complex administrative burden for states as they implement the program. NACAA encourages EPA to consider revisions to this structure to better align leak detection incentives and reduce the potential state administrative burden.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 17

Comment: Hess proposes that the Proposed OOOOa Rule: ... 2) allow an operator to reduce the frequency of inspections to one every three years for non-leaking sites;

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Patrick Von Bargen, Executive Director
Commenter Affiliation: Center for Methane Emissions Solutions (CMES)
Document Control Number: EPA-HQ-OAR-2010-0505-6980
Comment Excerpt Number: 5

Comment: The EPA should not predicate frequency of inspections on percentages of components found to have leaked in the immediate past. There are two reasons for this:
a. First, given that one of the causes of leaks is operator error, worker maintenance and operating mistakes can occur randomly and trigger leaks from otherwise the most effective components. And those errors may also cause large, super-emitting leaks. Past performance in this case is not a good predictor of future outcomes.
b. Second, the incentives such a rule creates can be perverse. They may motivate producers not to find leaks and fix them, but rather to manage the detection and reporting of leaks to come within certain component percentage thresholds. Such a rule would divert producers from the main goals of the rule itself.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 16

Comment: Fixed frequency preferred over proposed performance-based frequency. EPA's proposal based on the percentage of leaking components to determine frequency would be extremely difficult to calculate and track. Permian Basin operations, for example, are spread over hundreds of square miles and multiple counties in west Texas. It would be virtually impossible to keep track of varying frequencies of all of the facilities being constructed or considered modified by bringing in new wells, in addition to executing the surveys that would be required. For instance, having to travel to a remote area to survey a tank battery that may be on a quarterly basis while all others in area are on a semi-annular basis would be an enormous burden and would stress our already thin field personnel; particularly once all the leaks found to put a certain site in quarterly status were repaired. Once fugitive emissions leaks from well sites specifically are found, fixed and resurveyed per rule, there is no reason to believe that a specific site is more likely to have leaking fugitive components and would require more frequent surveying. Once components are fixed and resurveyed, more frequent subsequent surveys are not warranted. In Pioneer's Colorado asset area currently complying with the LDAR provisions in Regulation 7, fewer leaks were found in subsequent years. As IPAA/AXPC point out, there is no direct correlation between the number of leaking components and quantity of emissions (especially once these are fixed), so basing the frequency on percentage of leaking components does not necessarily mean the program will be more effective at preventing fugitive emissions.

Further, recent data demonstrates that production fugitive emissions are characterized by a few sources ("fat tails") representing the overwhelming majority of emissions. In the EDF/UT study of pneumatic controllers, dated December 9, 2014 revealed that 81% of the devices accounted for 5% of emissions and as follows, that only 19% of devices accounted for 95% of emissions. The majority of these controller emissions were the result of malfunctions that if fixed, should no longer leak. This "super-emitter" trend was demonstrated in a number of other sector studies sponsored by EDF and thus is reasonable that the expectation of a fat tail exists for component fugitive leaks. This data clearly demonstrates further the lack of rationale behind increasing frequencies once fugitive components are repaired.

Concurring with IPAA/AXPC's comments, if EPA persists with the percentage-leaking component approach, flexibility should be built into the program that companies could commit to semi-annual surveys and not be subject to fluctuation from quarterly to annual surveys based on the number of components leaking. The consistence of semi-annual reporting without the risk of quarterly monitoring would be more beneficial than the changing requirements and potential cost saving of annual surveying. Operators should be given the flexibility to choose. Flexibility in complying with the LDAR program will help reduce the cost and burden as well as improve the effectiveness of the program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 44

Comment: We strongly recommend that EPA remove provisions allowing operators to reduce frequency based on the percentage of leaking components identified in prior surveys. If the agency retains some provisions allowing frequency adjustment, those thresholds must be tied to emissions intensity. In addition to requiring operators to conduct leak surveys, the agency must require operators to accurately quantify site-level emissions in order to qualify a site for reduced-frequency inspections. While this would begin to address the disconnect between the metric for changing the frequency of inspections and actual emissions, we do not recommend that EPA take this approach. Indeed, even if emissions had been accurately quantified by EPA, studies suggest that past emissions are not a good predictor of future emissions given the prominent role that improperly functioning equipment, poorly maintained equipment, and other random events play in overall emissions. Facilities with low emissions during one survey may nonetheless experience such an event in the future, and less frequent monitoring at these sites would delay repairs to end these important and harmful emissions. Accordingly, we recommend EPA finalize LDAR standards based on fixed frequencies.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Anonymous public comment
Commenter Affiliation: Anonymous public comment
Document Control Number: EPA-HQ-OAR-2010-0505-7064
Comment Excerpt Number: 2

Comment: Comment #2. Citation: §60.5397a(h) & §60.5397a(i) First off, functionally, what do we use for the denominator if we do not have a component inventory (which is dictated or implied in OGI programs)? If we solve that by some engineering estimate or permit estimate or by requiring periodic counts and/or periodic count validations ... see comment #2A

§60.5397a(h) The monitoring frequency specified in paragraph (g) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than 3.0 percent of the fugitive emissions components at a well site or at greater than 3.0 percent of the fugitive emissions components at a compressor station.

§60.5397a(i) The monitoring frequency specified in paragraph (g) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. The monitoring frequency shall return to semiannual if a survey detects fugitive emissions between 1.0 percent and 3.0 percent of the fugitive emissions components at the well site, or between 1.0 percent and 3.0 percent of the fugitive emissions components at the compressor station.

Comment #2A: We need language in red in figure below to complete the skip period monitoring cycle language (above) of h & i or add a (h)(1) & (i)(1).

[Commenter included a diagram titled OGI monitoring Frequencies]

See the SOCMI HON Rule (40 CFR 63.168(d)(1 thru 4) - Valves in Light Liquid or Gas/Vapor service and 40 CFR 63.174(b)(3)(i thru iv) Connectors in light liquid or gas/vapor service)for example of completion of a skip period monitoring cycle i.e. moving to less frequent back to more frequent with a codified clear path based on historical leak frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Interfaith Center on Corporate Responsibility (ICCR)
Commenter Affiliation: Interfaith Center on Corporate Responsibility (ICCR)
Document Control Number: EPA-HQ-OAR-2010-0505-7068
Comment Excerpt Number: 7

Comment: We are particularly concerned about provisions in the rule that allow oil and gas companies to skip leak detection surveys when they report finding relatively few leaks at these sites. Recent studies show that a facility's percentage of leaking equipment is not an accurate predictor of its emissions. A company may have a small percentage of leaks, but they may be significant in size. Studies show that there is a high degree of unpredictability and randomness to leaks, with super-emitters resulting from human error, manufacturing defects, and/or wear and tear. Frequent, regular monitoring with leak detection equipment is necessary to prevent climate related pollution and negative impact on the health of communities, as well as to reduce the loss of valuable product. We are also concerned that allowing oil and gas companies to skip inspections based on the results of prior inspections may incentivize them to ignore or overlook leaks so they can skip the next survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 7

Comment: The two things that I saw in one of the documents that you guys had online, which was the summary proposed requirements for processes and equipment at natural gas well sites, specifically, I saw one statement that said, Any leaks found during the surveys would have to be repaired within 15 days unless the repair requires shutting down the production. In that case, owner/operators would be required to fix the leak at the next scheduled shutdown.

I absolutely do not agree with this. If there's a leak, they need to fix it. They need to fix within 15 days. I believe they need to fix it sooner than that. They have the technology. You already know that to repair these leaks, the cost is minuscule compared to what they're doing. And the dangers of the methane emissions and the other VOCs is too great to our environment.

The next area that I saw was that the proposed rule includes a sentence for minimizing leaks. It says, If leaks are found from less than 1 percent of covered components during two consecutive surveys, owner/operators may conduct the monitoring survey yearly, instead of every six months. I don't agree with this either. We have heard previous testimony, and I think it should be kept to three months or less.

I thank you for your time, and I appreciate all of your efforts.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12 regarding changes in monitoring frequency based on performance. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. With respect to time for repairs, see sections VI.F.1.e and VI.F.2.d of the preamble to the final rule.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 87

Comment: However, we hope EPA will improve the final rule by requiring owners and operators to frequently inspect their facilities either on a monthly or a quarterly schedule with no step-up or -down provisions based on the number of leaks they find.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding changes in monitoring frequency based on performance. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 241

Comment: In addition, allowing facilities to skip inspections based on prior results has the potential to increase harmful leaks. For one, past performance doesn't accurately predict current or future performance; new leaks pop up all the time. And it sort of creates an incentive to ignore leaks, in order to be able to skip the next inspection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 51

Comment: EPA should ensure that operators are not faced with a conflict of interest with respect to their role in how adjustments are made in the frequency of leak inspections.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 13

Comment: Based on the proposed regulation, we are expecting to survey every affected facility on a quarterly basis, which increases our reporting requirements by two to four times EPA's estimates. A typical well site has 25 to 50 potential leak points, or Fugitive Emission Components, as EPA defines on Page 255 of the regulation. If emissions are found from one or two of these components, our failure rate exceeds the required 3% threshold; which requires quarterly monitoring. Our well locations do not have thousands of potential leak points like refineries and chemical plants. A single leak has a large impact on our monitoring frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 16

Comment: Further, EPA must simplify the ongoing monitoring requirements proposed in 40 C.F.R. §§ 60.5397a(g)-(i). As proposed, affected facilities would be subject to different monitoring frequencies, ranging from quarterly to annually, based on the number of leaks from fugitive emissions components identified during prior monitoring surveys. Basing monitoring frequency on prior leak performance will create more recordkeeping requirements and will be burdensome for operators who will be forced to track all component counts and changes that occur at each individual station. In addition, GPA does not believe it was EPA's intent to require operators to count and tag every "fugitive emissions component" at the compressor station, which would be required to calculate leak percentages. Nor does GPA believe that such a monitoring schedule is necessary to provide an incentive for operators to reduce leaks from fugitive emissions components. Instead, such requirements will simply add unnecessary burdens and complexity to what is already a complicated and costly monitoring program.

Thus, GPA proposes that all compressor station sites should be subject to a fixed, annual monitoring schedule with monitoring events to be separated by at least 180 days, but not be extended more than 12 months from the previous monitoring event. Past experience has shown that such a monitoring schedule will be effective in identifying and repairing leaks from compressor station sites in a timely manner. In fact, data collected by GPA members as part of Colorado's Regulation 7 fugitive monitoring program has shown that even during initial monitoring surveys, the percentage of leaking components is below the 1% threshold EPA is proposing for annual monitoring. Out of the 15 sites monitored, the highest leak percent was 0.38%. Thus, both the complexity and costs of EPA's proposed monitoring schedule as well as the history of state-based monitoring programs establishes that a requirement for annual monitoring will be sufficient to detect and repair leaks in a timely manner.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 35

Commenter Name/Affiliation: W. Michael Scott / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 32

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 31

Commenter Name/Affiliation: Glenn Prescott; W / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 32

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 32

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 33

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 32

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 70

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 10

Commenter Name/Affiliation: Michael Hollis /Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 27b

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 26b

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 23b

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 23b

Comment: The Methane NSPS also adjusts the frequency of survey requirements from semi-annually to annually, or from semi-annually to quarterly, based on the percentage of components found to be leaking during two consecutive surveys.

This method of determining survey frequency is problematic. First, without being able to accurately count the number of components at the well site or compressor station, an operator cannot be certain what percentage of their components are leaking, and thus whether their survey leak detection timeline should be adjusted. This is particularly problematic given the very small margin of error before the survey times adjust: An operator will have different survey frequencies depending on whether less than one, two, or just over three percent of their components are leaking. Yet, how can they determine what percentage of their components are leaking if they cannot accurately establish the number of components at the well site or compressor station? This problem is further exacerbated by the fact that some equipment at these sites is excluded from the definition of "fugitive emissions component" because it is equipment that emits natural gas as part of normal operations. Without greater clarity in the definition, operators may be uncertain how to classify certain equipment, and may unintentionally miscount their components.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6703, Excerpt 26, for information related to the definition of "fugitive emissions component".

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 15

Comment: The use of OGI instruments for leak detection and possible quantification is a new technology. The TCEQ recommends that the EPA evaluate the frequency of monitoring (quarterly, semi-annually, or annually) after three or four years of data and make adjustments as necessary. The EPA should also consider a monitoring frequency of every two years, instead of yearly, for some sites if the data supports the monitoring time extension.

Response: The EPA monitors the effectiveness of rule requirements and compliance strategies and will continue to evaluate these requirements in the future. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 14

Comment: We recommend an adequate and sufficient number of inspections, performed at different intervals by both the operator and regulator in order to assure that well sites are achieving, and will continue to achieve, equal or better emission reductions than the proposed standards.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. We note that we are not requiring regulators to perform monitoring surveys, but we are aware that air agencies sometimes perform monitoring surveys as part of inspection routines.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 53

Comment: Though Kinder Morgan appreciates that EPA has attempted to provide an incentive by including a step-down monitoring program, EPA's requirement for facilities to "step-up" in certain circumstances eliminates the incentives created by the step-down program and requires significant effort and evaluation on the part of companies for each and every facility. Specifically, EPA's proposed step-up and step-down program, without further elaboration from EPA, appears to require either a component count or component tagging at each and every facility in order for the company to determine if greater than 3 percent of the components are leaking (and thus require increased monitoring) or less than 1 percent of the components are leaking (and thus allow for decreased monitoring). For a variety of reasons, EPA's proposed step-up program is not cost-effective and the step-down program does not provide the necessary incentives to operators. In addition, the step-up and step-down provisions overly complicate implementation of the LDAR programs at individual or across multiple facilities owned by a company (e.g., when would a facility step-up or step-down to quarterly or semiannually in any given calendar year, for example?). The changing frequency would inherently lead to system-wide compliance tracking issues.

First, Kinder Morgan's experience with leak detection indicates that rarely, if ever, upon implementation of a leak detection program, the percentage of leaking components will increase to above 3 percent over time. As discussed in Section F, above, over time, leak detection programs almost always remain fairly constant and LDAR programs more often have diminishing returns with regard to emission reductions per subsequent survey event.

Second, the step-up requirement could require well sites and compressors with limited emissions to complete a component count despite the limited emissions reductions that may be obtained or realized from these facilities. Through Kinder Morgan's extensive experience implementing LDAR programs, the average cost of a component count at a facility is approximately $2,000-$3,000. This is a potentially significant cost in light of the number of facilities that will be affected by the Proposed NSPS OOOOa Rule. Though Kinder Morgan proposes elimination of the step-up program entirely, EPA could reduce some of the concerns that a component count would be required by allowing owners and operators to utilize standard component counts previously developed for the GHG reporting program. Importantly, EPA did not include in its cost analysis, the significant costs of completing an annual component count requirement, which are important factors in evaluating the cost-effectiveness of this proposal.

Finally, the step-up and step-down provisions are based on the percent of total leaking components at a given facility with no regard for the amount of emissions being emitted by the leaking components. Any step-up or step-down provision should be based on an emissions threshold in tons per year. For example, a facility could have no "gross emitters" and a total component leak rate exceeding 3 percent, but the total emissions from those leaks could be very small (e.g., less than one (1) tpy). Under the Proposed NSPS OOOOa Rule, the facility would still be required to conduct quarterly leak surveys, with minimal resulting environmental benefits.

Thus, Kinder Morgan's preferred approach would be to eliminate the step-up / step-down program in its entirety. Kinder Morgan proposes the following language in this regard:

Proposed Revisions to EPA's § 60.5397a:

> (~~g~~**d**) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station shall be conducted at least ~~semiannually~~**annually** after the initial survey. Consecutive ~~semiannual~~**annual** monitoring surveys shall be conducted at least ~~4~~**10** months apart.
>
> ~~(h) The monitoring frequency specified in paragraph (g) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than 3.0 percent of the fugitive emissions components at a well site or at greater than 3.0 percent of the fugitive emissions components at a compressor station.~~
>
> ~~(i) The monitoring frequency specified in paragraph (g) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. The monitoring frequency shall return to semiannual if a survey detects fugitive emissions between 1.0 percent and 3.0 percent of the fugitive emissions components at the well site, or between 1.0 percent and 3.0 percent of the fugitive emissions components at the compressor station.~~

In the alternative, EPA could reduce some of the concerns that a component count would be required by allowing owners and operators to utilize standard component counts previously developed for the GHG Reporting Program. Specifically, utilizing EPA's Default Average Component counts would eliminate the need for a costly component count.

If EPA retains any sort of step-up program, it should be extremely limited in nature. Instead of basing any step-up program on a percentage of all components at the facility, any step-up should only be required on individual components that are determined to leak over time despite repair. This recommended concept is consistent with the "gross emitter" discussion provided above.

In certain circumstances, providing a step-down program provides an incentive to companies that want to reduce their survey frequencies, realize reduced costs, and improve efficiencies. However, the step-down program should be optional and companies that do not wish to step down should not be required to undertake the additional effort of counting or tagging components. Kinder Morgan provides proposed revised language reflecting this alternative approach below.

Alternative Proposed Revisions to EPA's § 60.5397a:

(**e**~~h~~) **With respect to a particular component,** the monitoring frequency specified in paragraph (~~g~~**d**) of this section shall be increased to semi-annual in the event ~~that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than 3.0 percent of the fugitive emissions components at a well site or at greater than 3.0 percent of the fugitive emissions components at a compressor station~~ **that a particular component is determined to be consecutively leaking for three surveys in a row. Monitoring frequency for the subject component may be decreased to the monitoring frequency specified in paragraph (d) if the operator completes at least two consecutive surveys with no leaks from that component.**(~~i~~**f**) The monitoring frequency specified in paragraph (~~g~~**d**) of this section may be decreased to ~~annual~~**every other year** in the event that two ~~consecutive semiannual~~**annual** surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. The monitoring frequency shall return to ~~semiannual~~**annual** if a survey detects fugitive emissions between 1.0 percent and 3.0 percent of the fugitive emissions components at the well site, or between 1.0 percent and 3.0 percent of the fugitive emissions components at the compressor station. **For purposes of this provision, in determining the percent of fugitive emissions components at which fugitive emissions were detected, operators may use EPA's Default Average Component counts identified in 40 C.F.R. Part 98, Subpart W.**

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Shawn Bennett, Executive Vice President
Commenter Affiliation: Ohio Oil & Gas Association (OOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6921
Comment Excerpt Number: 14

Comment: MONITORING FREQUENCY—60.5397a(h)

Because quarterly monitoring can be costly and time-consuming, the proposed rule should be revised to allow for a return to semiannual reporting after four (4) consecutive quarterly readings of less than 2% leaking components. It should also allow for annual monitoring after two consecutive readings of less than 2% leaking components thereafter in order to be consistent with Ohio's GP-12 program.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 9

Comment: The proposal requires that the frequency of leak monitoring be increased or decreased depending on the results of two consecutive semi-annual surveys. We strongly encourage EPA to maintain the annual measurement frequency for the reasons described here. First, to determine the percentage of leaking components, an inventory of fugitive components at the entire station (even components which are not "new" or "modified") would need to be developed, which is well beyond the scope of the proposed regulation. Second, maintaining a consistent frequency for monitoring and repair enables better planning and implementation from an operational perspective. Third, we are very concerned about the availability of qualified outside contractors who can perform the leak monitoring using the Optical Gas Imaging (OGI) technique compared to other methods (Method 21, for example) for regulatory compliance purposes. The ability to schedule these outside contractors at all of the affected facilities based on a moving target at each facility is not feasible. The only practical way to implement this program and ensure timely completion of inspections at each facility is to schedule this based on an annual and well-regulated schedule. In summary, we do not support the varying monitoring frequency for the leak monitoring and repair program and request that EPA change this to an annual inspection of NSPS applicable equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See sections VI.F.1.c and VI.F.2.b for discussion on the use of Method 21 to monitor for fugitive emissions.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 18

Comment: As an initial matter, the rule "find[s] that the cost of monitoring/repair based on quarterly monitoring at well sites using [optical gas imaging, or OGI] not cost-effective under either [the single- or multipollutant approach]." 80 *Fed. Reg.* at 56,636 (emphasis added). Given the inaccuracies in EPA's assessment of costs, as described in more detail herein, MarkWest agrees with this conclusion, and believes that if more accurate cost and benefit data were used, quarterly monitoring at well production facilities would be even more costly per ton of pollutant reduced (i.e., less cost-effective) than estimated in the proposal, and even semi-annual monitoring would be shown to be not cost-effective, as well. In light of this express finding by EPA, there does not appear to be any legal authority to impose a "step-up" approach that would require operators with higher than a 3% leak rate over a 12-month period to move to quarterly monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 20

Comment: The proposed LDAR program is tantamount to similar LDAR requirements for gas plants, refineries and chemical plants. Unlike those facilities, however, well sites and compressor stations are typically unmanned, widely dispersed geographically, and typically do not provide operators with easy access to spare parts for making repairs. It is unreasonable to expect a record of every valve, flange, and gasket across thousands-or, possibly tens of thousands-of wells and compressor stations, and then to track changes to the same year-after-year. The data management burdens alone are not practical or reasonable, and the implementation burdens that would be required are daunting, including hiring crews, training on component identification, implementing a tagging program, etc. Moreover, the costly and complex undertaking of building and maintaining such a database imposes significant costs on operators, and ultimately end consumers, while providing no environmental benefit. The rule should not include a program provision that would require extensive data management of this type (i.e., no step-up/step-down provision).

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Camilla Feibelman
Commenter Affiliation: Rio Grande Chapter of the Sierra Club
Document Control Number: EPA-HQ-OAR-2010-0505-6895
Comment Excerpt Number: 8

Comment: EPA's proposal would allow operators to reduce the frequency of inspections in the future if they find that the percentage of leaking equipment falls below certain thresholds. This would encourage bad operators to ignore or overlook leaks in order to qualify for less frequent inspections. EPA must remove this perverse incentive from the final rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Seth B. C. Shonkoff, Executive Director, Jake Hays, Director, Environmental Health Program and Renee L. Santoro Director, Energy Environment Program,
Commenter Affiliation: PSE Healthy Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6951
Comment Excerpt Number: 9

Comment: Leak Detection and Repair. EPA should strengthen the standards for leak detection and repair (LDAR), as the proposed rule requires semi-annual inspections and includes counterproductive provisions that allow oil and gas companies to skip surveys when they report finding relatively few leaks at these sites. Continuous real-time monitoring is preferable and inspections should be done monthly or quarterly with straightforward, fixed frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. At this time, we do not believe that cost-effective continuous monitoring technology exists that would provide adequate data on fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 42

Comment: EPA's Rationale for Adopting Frequency Step-Downs Is Arbitrary and Not Supported by the Record.

In addition to proposing baseline, semi-annual monitoring requirements—which, as we describe above, would be less stringent than most existing state programs—EPA has further proposed to allow operators to adjust site monitoring frequency based on the percentage of leaking components found during a survey. In particular, the agency has proposed to allow sites to perform less-frequent annual inspections if, in two successive surveys, operators find less than 1 percent of components leaking. 80 Fed. Reg. at 56,637. Conversely, if more than 3 percent of components are leaking, operators would have to monitor quarterly. *Id*. The agency's rationale suggests that the proposal is meant to reward operators for achieving low emissions. While well-designed policy incentives can enhance emissions performance, EPA's proposed frequency adjustments are arbitrary, misalign incentives for operators, and are almost entirely divorced from a facility's emissions performance. Indeed, they reward facilities with potentially substantial emissions while applying more rigorous standards to sources that may be more modest polluters.

EPA's proposal creates perverse incentives by rewarding operators for failing to identify harmful leaks. This is not a hypothetical concern. A 2007 report by EPA found "significant widespread non-compliance with [LDAR] regulations" at petroleum refineries and other facilities. EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions." The report recommends that "[t]o ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time," companies should monitor more frequently. Instead, EPA should establish a rigorous baseline and reward operators for finding leaks more quickly and accurately—maximizing environmental benefits while minimizing costs. In subsection [F], below, we recommend an innovation pathway that could help to better align these incentives.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 28

Comment: We believe that the monitoring frequency and thresholds that have been established in this proposed regulation will be a major challenge to our industry, and may not be achievable. Well heads, tank batteries, and compressor stations do not have a large number of potential leak points like oil refineries and chemical plants that may have an excess of 10,000 potential fugitive emissions components that are monitored.

Figure 3 shows a typical well head design, which contains a small number of Fugitive Emission Components, as defined on Page 255. "Fugitive Emission Component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters."

Figure 3. Typical Well Head Design

Depending on the wellhead design, 50 – 70 components will meet the definition of a Fugitive Emission Component. A typical tank battery will only have another 40 – 50 components that meet the definition of a Fugitive Emission Component. Using the proposed regulation, three leaks at a facility will require the owner/operator to monitor the facility on a quarterly basis. We believe that this threshold is too low. We propose to simplify the monitoring requirements as follows: if emissions are found from ten percent or more components, the owner / operator will monitor the facility semi-annually, but if emissions are found from less than ten percent of the components, then the owner/operator will monitor annually.

We believe that most leaks that have been repaired and certified with the follow-up survey will not leak again. The additional survey requirements will add significantly more cost to our operation than the benefit of reducing emissions.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Clement J. Frost, Chairman
Commenter Affiliation: Southern Ute Indian Tribe Council
Document Control Number: EPA-HQ-OAR-2010-0505-6446
Comment Excerpt Number: 3

Comment: Regarding leak survey timing and leak detection rates, the Tribe recommends limiting the performance-based leak survey frequency to either semi-annual or annual monitoring and set the percent of fugitive emission components metric at three to five percent. The proposed metrics of one percent and three percent have the potential to create a more complex and confusing regulatory and compliance scenario. In many cases one percent of fugitive emission components are less than five components. This has the potential for facilities, under the proposed metrics, to be constantly moving between quarterly, semi-annual, and annual leak monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 34, 48

Comment: The PBPA also believes that the currently proposed metrics of 1% and 3% are overly conservative when very small leaks are observable using OGI technology. Camera manufacturers state that under the ideal conditions, leaks of less than 2 grams per hour can be observed. As the rule is proposed, a facility that identifies and repairs three 2 g/hr leaks and has 100 components must now increase its monitoring frequency. This would be required for leaks that were repaired and totaled a mere 6 g/hr. The PBPA suggests that the leak thresholds be changed to 5% and 10% respectively.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 36

Comment: As stated, PIOGA supports the concept of performance based criteria but suggests that the criteria be revised to include specific quantities of components for affected sources with total component counts less than the model plant described in the technical support document. PIOGA suggest the use of 16 components and 5 components, corresponding to 3% and 1% of the component count for the model plant in the TSD. The use of specific quantities of components as criteria will provide flexibility for small affected facilities.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 38

Comment: Second, at least five recent peer-reviewed studies have found that methane leaks from natural gas development are already well below the 3.2 percent leakage threshold, the rate at which scientists believe natural gas may lose its greenhouse gas advantage.

Response: The EPA recognizes the concern of the commenter that EPA rules work to enhance resource recovery and minimize the burden of compliance. The EPA consulted extensively with industry stakeholders through an open process to gather data and propose control measures and techniques that, by virtue of being the industry best practices in the field, could appropriately be considered the Best System of Emission Reduction (BSER), the criterion by which EPA adopts a standard under the NSPS. We used the comment and response process to further refine our proposal. The final requirements reflect additional input provided during the comment period from industry and the public and are efficient and effective safeguards for industry to follow.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 65

Comment: The current wording of "flexibility of inspections depending on the percentage of leaks in the previous 12-month period" is completely unacceptable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Steven A. Buffone
Commenter Affiliation: CONSOL Energy Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6859
Comment Excerpt Number: 16

Comment: If EPA decides on semi-annual OGI monitoring surveys on an annual basis for new and modified well sites, CONSOL would encourage EPA to include the option for decreased survey frequency from semiannually to annually for sites that find fugitive emissions from less than one percent of their fugitive emission components during a survey, while the frequency would increase from annually to semi-annually for sites that find fugitive emissions from three percent or more of their fugitive emission components during a survey. Any more frequent monitoring requirements should be left to the discretion of the state regulatory agency and the individual operator.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Shawn Bennett, Executive Vice President
Commenter Affiliation: Ohio Oil & Gas Association (OOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6921
Comment Excerpt Number: 13

Comment: MONITORING FREOUENCY—60.5397a(h)

Absent an exemption as requested in the General Comments above, the proposed LDAR monitoring requirements should be revised for consistency. The proposed rule requires quarterly monitoring in the event that two consecutive semiannual monitoring events detect greater than 3% leaking components and the rule provides no way for a facility to return to less frequent monitoring. That requirement is inconsistent with Ohio's GP program which allows a return to semiannual monitoring after four (4) consecutive readings of less than 2% leaking components. Ohio's GP also allows for annual monitoring if one year of semiannual monitoring shows less than 2% leaking components. EPA also needs to clarify how the leak percentage is to be calculated under the proposed rules as it is unclear as written.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Michael Turner, Senior Vice President, Onshore
Commenter Affiliation: Hess Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6960
Comment Excerpt Number: 11

Comment: Finally, Hess does not support the proposed metrics of one percent and three percent of components specified in the Proposed OOOOa Rule because these metrics require performing and maintaining a count of all fugitive components. The proposed metrics included in the Proposed OOOOa Rule are based on a direct count of all fugitive components, which can be time consuming and costly. If EPA elects to use a component count, Hess agrees with API's proposed simplified approach, such as the 40 CFR 98, Subpart W, upstream component count approach, which only requires a count of major pieces of equipment, which are combined with EPA assumptions on component counts per equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 26

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 24

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 23

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 24

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 24

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 25

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 24

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 23

Comment: Finally, using a percentage of components, rather than a set number of components, to determine the frequency of surveys is also unfair to small entities. A small site will have fewer fugitive emission components than a larger site. As a result, each leaking component will represent a greater share of the total number of components. While a site with 5,000 components can afford to have 50 leaks without any impact on the frequency of its survey requirements, 50 leaks at a much smaller site with only 1,000 components would trigger more frequent survey requirements under the Rules. Smaller entities are much more likely to operate these smaller sites, and thus are more likely to face more frequent survey requirements under the percentage-based system. Smaller entities are, therefore, more likely to have additional survey requirements, despite the fact that there is no reason to believe that 50 leaking components at a small site have a more meaningful impact on emissions than 50 leaks at a larger site.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 54

Comment: Though Kinder Morgan proposes elimination of the step-up program entirely, EPA could reduce some of the concerns that a component count would be required by allowing owners and operators to utilize standard component counts previously developed for the GHG reporting program. Importantly, EPA did not include in its cost analysis, the significant costs of completing an annual component count requirement, which are important factors in evaluating the cost-effectiveness of this proposal.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: C. Wyman
Commenter Affiliation: American Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-6874
Comment Excerpt Number: 9

Comment: EPA's proposal would include a performance based survey frequency that would depend on the scope of leaks – the frequency would vary from quarterly to annually depending on the percentage of components from which fugitive emissions were detected. Requiring operators to conduct a component count to assess the percentage of leaking components would add an unnecessary burden for minimal benefit.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 27

Comment: We'd like the frequency of inspections at a quarterly rate. We would like that not to be tied to a percentage of leaks, and we'd like to have resurveys done with the same technology that found the leak.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

While the rule does not specify the technology that must be used to resurvey components with fugitive emissions, we expect that the same technology that was used to find the fugitive emissions would be used to resurvey the component once it is repaired.

Commenter Name: Karen Sjoberg, Chairperson
Commenter Affiliation: Citizens for Clean Air (CCA)
Document Control Number: EPA-HQ-OAR-2010-0505-5288
Comment Excerpt Number: 4

Comment: The EPA proposal rightly addresses methane leaking, flaring and venting in oil and gas operations during drilling and delivery processes. However, we urge you to mandate leak detection and repair surveys on a fixed basis, quarterly or monthly. The proposal, which would vary the frequency of inspections, would incentivize operators to ignore leaks in order to qualify for less frequent inspections.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: J. Young; T. Bacci
Commenter Affiliation: Citizen; Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6469; EPA-HQ-OAR-2010-0505-6471
Comment Excerpt Number: 7; 5

Comment: We urge the -- you to improve the proposed rules to include: Mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection;

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: S. Hathaway
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6473
Comment Excerpt Number: 4

Comment: We urge you, even knowing that it's futile, to improve the proposed weak rules to include:

Mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate detection (which will probably be a lie, anyway);

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, for information related to a fixed monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 12

Comment: We recommend mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection. Fixed frequencies will more than likely ensure the operator has a robust maintenance and repair and LDAR program.

We advocate a straightforward approach to monitoring fugitive emissions at well sites [and compressor stations]. We recommend mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection. In general, when more stringent requirements are in effect, there is a greater assurance that the operators will have a robust maintenance and repair program that will keep fugitive emissions to the minimum. Lacking that, human nature being what it is, operators may not give the warranted attention necessary to keep fugitive emissions to the lowest possible levels.

We recommend including low production well sites for fugitive emissions complying with the same monitoring requirement - at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection. In general, when more stringent requirements are in effect, there is a greater assurance that the operators will have a robust maintenance and repair program that will keep fugitive emissions to the minimum. Lacking that, human nature being what it is, operators may not give the warranted attention necessary to keep fugitive emissions to the lowest possible levels.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12 regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. With respect to low production wells, we have removed the exemption for fugitive emissions monitoring at low production well sites. See section VI.F.1.b of the preamble for a discussion on this issue.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 21

Comment: We recommend mandatory well site monitoring surveys at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection. A best practice would dictate that operators would regularly monitor well sites for methane leakage as that is literally revenue dissipating in the air. Therefore, establishing a regular monthly or quarterly interval is a practice that benefits the operator through the savings of loss revenue. It also ensures a better environment for those who live or attend school near well sites that may have lower VOC fugitive emissions than may otherwise occur at sites inspected less regularly.

Well sites are fluid and dynamic; production levels decline, new wells are placed into production, malfunctions may occur. A performance-based frequency implies that the better the performances, the less likely frequent well site monitoring surveys are needed. This fails to take into account the dynamic nature of a well site. Therefore, we recommend mandatory well site monitoring surveys at least quarterly, preferably monthly.

We recommend mandatory compressor station monitoring surveys at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection. A best practice would dictate that operators would regularly monitor compressor stations for methane leakage as that is literally revenue dissipating in the air. Therefore, establishing a regular monthly or quarterly interval is a practice that benefits the operator through the savings of loss revenue. It also ensures a better environment for those who live or attend school near compressor stations that may have lower VOC fugitive emissions than may occur at sites inspected less regularly.

Compressor Stations are fluid and dynamic; production levels decline, new wells are placed into production, compressor engines are added, compressor engines are removed, new gathering lines are added, wells are shut-in, wells are returned to production; which results in changes in pressures and the number of operating compressor engines. On occasion human error during maintenance causes serious malfunctions to occur, and occasionally operations themselves create a malfunction. A performance-based frequency implies that the better the performances, the less likely frequent compressor station monitoring surveys are needed. This fails to take into account the dynamic nature of a compressor station. Therefore, we recommend mandatory compressor station monitoring surveys at least quarterly, preferably monthly.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: John Robitaille
Commenter Affiliation: Petroleum Association of Wyoming (PAW)
Document Control Number: EPA-HQ-OAR-2010-0505-6854
Comment Excerpt Number: 37

Comment: EPA should require only annual surveying, on a fixed annual frequency, with no performance based adjustment to the survey frequency. As proposed, a performance based frequency would require fugitive counts, which should be avoided. PAW believes there are diminishing returns of requiring shorter intervals for monitoring.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 9, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 128

Comment: API Advocates A Fixed Initial Annual Frequency, Regardless Of The Percent Of Leaking Components

EPA solicit comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action.

API does not support the proposed metrics of one percent and three percent of components specified in §60.5397a(i) and (h), respectively, as these metrics require maintaining a count of all fugitive components. API advocates a fixed initial annual frequency, regardless of the percent of leaking components. **Therefore, API recommends removing both paragraphs (h) and (i) in §60.5397a.**

To count and tag components at a compressor station, costs approximately $10,000 and requires continual maintenance and management. In a study performed by an API member company which compared three basic leak detection methods: AVO, OGI, and M21, component counts were made by a manual observer while on site. Because M21 was already being conducted, the additional cost of component counts was $15 to $58 per well site. However, if done in conjunction with an OGI method, the cost would be higher because individual components need not be individually located for the purposes of OGI monitoring. API companies estimate a cost of $120 per well site to count components initially, with a recurring cost of $60 per well site to validate and update the counts annually.

Proposed Approach To Allow Reduction In Monitoring Frequency Forces The Need To Develop Equipment Count For Each Well Site In Order To Properly Document The Percent Leaking Components. This Is Inconsistent With Subpart W Monitoring Program For Transmission And Storage

API does not support the proposed metrics based on a direct count of all fugitive components, which can be time consuming and costly. If EPA elects to use a component count, API recommends that a simplified approach, such as the 40 CFR 98 Subpart W upstream component count approach would be used [specified in §98.233(r)]; that method only requires a count of major pieces of equipment which are combined with EPA assumptions on component counts per equipment.

Recognize That Subpart W Already Requires Annual Fugitives Reporting For Certain Compressor Stations That Exceed The 25,000 Metric Ton CO2e Threshold, And Request Comments On The Overlap Of These Reporting Requirements

§60.5397a(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging.

(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station shall be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys shall be conducted at least 4 months apart.

For transmission compressor stations or storage stations that exceed the reporting threshold of 25,000 tonnes CO2e, Subpart W requires annual leak detection surveys at natural gas transmission and storage stations using Optical Gas Imaging, M21, or Infrared laser beam illuminated instrument [as specified in 40 CFR 98.233(q)(1) and 98.234(a)]. Subpart OOOOa is imposing a different frequency (semi-annual), more limited detection methods (OGI only), different reporting requirements, and a separate monitoring program than Subpart W for new or modified compressors stations. This creates duplicative and conflicting requirements. Subpart OOOOa should not apply to compressor stations currently regulated under Subpart W.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6882, Excerpt 27, for a discussion on the overlap between subpart OOOOa and subpart W.

Commenter Name: Henry Robertson, Energy Chair / Staff Attorney
Commenter Affiliation: Missouri Sierra Club / Great Rivers Environmental Law Center
Document Control Number: EPA-HQ-OAR-2010-0505-6913
Comment Excerpt Number: 3

Comment: The rule provides for annual and semiannual monitoring of leaks, and in some cases for even less frequent monitoring. But given the unpredictability of leaks, and their potential seriousness, the leak detection and repair (LDAR) requirements should include fixed and frequent monitoring schedules, quarterly at least.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Richard Eidlin, Vice President, Policy and Campaigns
Commenter Affiliation: American Sustainable Business Council (ASBC)
Document Control Number: EPA-HQ-OAR-2010-0505-6916
Comment Excerpt Number: 6

Comment: We also encourage EPA to require inspections for leak detection and repair at a fixed frequency of either monthly or quarterly surveys in order to protect communities near the oil and gas infrastructure. The approach proposed in the rule revision allows operators to go too long in between inspections and would allow companies to skip surveys when they report few leaks at the sites. This provision could lead to companies underreporting leaks in order to qualify for fewer surveys, and is likely to allow significant leaks to go unidentified even by companies fully complying with the rules due to the random nature in which leaks arise. EPA could mitigate these problems by setting a standard frequency of inspections for all operators.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 18

Comment: EPA proposes variable intervals for required fugitive emissions monitoring, such that that if fugitive emissions were detected from three percent or more of the fugitive emission components during two consecutive semiannual monitoring surveys, then the monitoring survey frequency for that station would be increased to quarterly; while if fugitive emissions were detected from less than one percent of the fugitive emission components, then the monitoring survey frequency would be reduced to annually.

Rather than pegging survey intervals to past performance, TPA believes that a fixed survey period, set on an annual basis, would be preferable. It would be too difficult to keep the records needed to calculate performance under EPA's current proposal; percentages (here, percentages of leaking components) are very hard to keep track of on an ongoing basis when companies are continuously buying, selling, and adding equipment, because the baseline is ever changing. Requiring companies to keep track of percentages of leaking components would only complicate an already extensive set of rules, and it would expose companies to enforcement actions even though they had done all they could do to comply with the rules. Compliance in some cases would basically require a company to set up a traditional LDAR program to keep up with equipment counts, percentages of leaking components, and the like. Companies might end up spending more money and effort tracking leak percentages than they would spend on finding leaks and fixing them. A fixed survey period would be far simpler and would eliminate these problems.

We recommend that the fixed survey interval be set on an annual basis. More frequent intervals would be unduly burdensome, given that compressor stations are very numerous and are often located in remote areas, as previously noted. Moreover, companies are used to reporting on an annual basis given that reporting under EPA's GHG reporting program is required annually, and this approach has apparently worked well for EPA in the reporting context. Indeed, in finalizing the initial GHG reporting rules in 2009, EPA stated not only that "annual reporting is sufficient for policy and regulatory development" but also that annual reporting is "consistent with other existing mandatory and voluntary GHG reporting programs at the State and Federal levels (e.g., The Climate Registry (TCR), several individual State mandatory GHG reporting rules, EPA voluntary partnership programs, the DOE voluntary GHG registry)."Additional reasons to set reporting on an annual basis also exist: first, the resources (e.g., OGI personnel and equipment) to comply with survey requirements may be limited, a concern that EPA itself acknowledges in the preamble and second, the natural gas industry is already incentivized to locate and repair methane leaks, with or without regulatory requirements, given that the natural gas of which methane is a part is the companies' life-blood product. The fact that companies have a clear economic incentive to find and repair equipment that is leaking methane probably explains why emissions of methane have consistently gone down in recent years, as previously noted.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 7

Comment: Frequency. Data from Chevron's existing leak detection/find and fix programs shows that there is already a very low leak rate, even will annual surveys. So little gas is recovered that it is likely there will be more greenhouse gas emissions from driving to remote sites than will be recovered through leak detection and repair. In states where Chevron implements regulatory required leak detection and repair programs, we currently find leak rates that range from 0.04% to 0.16% of components leaking. Increasing the inspection frequency to semi-annual is likely to result in little to no additional leak reduction, but will result in greenhouse gas emissions from vehicles being driven to sites for inspections. We recommend surveys be conducted annually at well sites.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Seth B. C. Shonkoff, Executive Director, Jake Hays, Director, Environmental Health Program and Renee L. Santoro Director, Energy Environment Program,
Commenter Affiliation: PSE Healthy Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6951
Comment Excerpt Number: 8

Comment: Leak Detection and Repair. EPA should strengthen the standards for leak detection and repair (LDAR), as the proposed rule requires semi-annual inspections and includes counterproductive provisions that allow oil and gas companies to skip surveys when they report finding relatively few leaks at these sites. Continuous real-time monitoring is preferable and inspections should be done monthly or quarterly with straightforward, fixed frequency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Jennifer Cassel, Staff Attorney
Commenter Affiliation: Environmental Law & Policy Center
Document Control Number: EPA-HQ-OAR-2010-0505-6994
Comment Excerpt Number: 5

Comment: Specifically, as delineated by our colleague Earthworks in their separate comments on this proposed rule, the draft rule should be revised to include: Required inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12., regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 45

Comment: Any periodic OGI monitoring should be on a fixed annual basis. TXOGA agrees with the information presented by the American Petroleum Institute in support of this provision which show the diminishing returns of OGI and the importance of focusing on the high emitters. In sum, the API data on the leaks identified from recurring LDAR surveys indicates that annual LDAR is sufficient for identifying and correcting the relatively few fugitive sources with very high emission rates. We note that EPA's proposed variable approach where annual monitoring could be used when there is a less than 1 percent leak rate is unworkable because it requires the tracking of component counts for validation.

To the extent EPA nonetheless proceeds with a semi-annual requirement, it is essential that any program involve representative monitoring and provide for reduction in frequency when results that indicate low leak rates are obtained.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 38

Comment: EPA Should Strengthen the Frequency of LDAR in the Final Rule and Remove Frequency Adjustment Based on Percent of Leaking Components.

Given the geographic and temporal unpredictability of leaking equipment, one of the most important aspects of such a program is the frequency with which operators inspect facilities. EPA has proposed semi-annual leak inspection surveys, with provisions to allow operators to adjust frequency based on the percentage of leaking components found onsite. These provisions fall far short of what is necessary to protect public health and the environment, and lag behind what leading states and companies have already demonstrated in practice. Accordingly, EPA's proposed requirements do not reflect a BSER determination in accordance with section 111, and the agency must strengthen the baseline frequency of inspections in the final rule and remove the proposed step-down provisions.

In subsections i and ii, we outline the flaws in EPA's rationale for rejecting more frequent monitoring at well sites and compressor stations and for adopting frequency step-downs. In subsection iii, we summarize state and industry experience showing that more frequent monitoring is cost-effective. In subsection iv, we provide our recommendations to EPA, summarized as follows:

- EPA must require quarterly LDAR at well sites and compressor stations, or alternatively, adopt a tiered monitoring approach for well sites along the lines reflected in the Colorado rule.

- EPA must eliminate provisions allowing operators to reduce inspection frequency based on the percentage of leaking components.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name/Affiliation: Julie Archer, Project Manager and David McMahon, J.D., Co-Founder; West Virginia Surface Owners' Rights Organization (WVSORO)
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-7066; 8

Commenter Name/Affiliation: Terry Lansdell, Program Director; Clean Air Carolina
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-7241; 3

Comment: In addition, we urge you to improve the proposed rules to:

Require mandatory inspections at least quarterly or monthly (rather than a default semi-annual requirement), which should remain at a fixed frequency, rather than decreasing upon low leak rate-detection;

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 48

Comment: Second, EPA's preferred work practice standard for fugitive emissions from well sites and compressor stations does not go far enough. EPA states in its proposal that it believes a facility with proper operation would likely find one to three percent of components to have fugitive emissions. Following this line of reasoning, EPA's proposal will allow an owner/operator that finds less than one percent of a facility's equipment to be leaking to decrease the frequency of their LDAR inspections to annually for as long as the proportion of equipment leaking at the facility remains below one percent.

Under the Clean Air Act, EPA's work practice standards must reflect the best technical -- technological system of continuous emission reduction. EPA's proposed standard for fugitive emissions does not rise to this level.

Besides incentivizing an owner/operator to not discover leaks, the Agency's preferred work practice standard assumes that there is a relationship between the percentage of pieces of leaking equipment and the actual emissions from the facility.

However, data from the City of Fort Worth Natural Gas Air Quality study and the University of Texas study show that the magnitude of emissions from facilities can be largely independent of the percentage of leaking equipment.

The total fugitive emissions are not tied to the number of pieces of leaking equipment and thus the variable frequency that would be required by the proposal does not constitute the best technological system of continuous emission reduction as required by section 111(h).

Indeed, the best system to reduce emissions from fugitive -- excuse me. The best system to reduce emissions from fugitive emissions is to implement a fixed quarterly inspection frequency at a minimum.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 4

Comment: We just encourage the EPA to go a little bit further by requiring fixed inspections, instead of being based on previous performance. And we encourage the EPA to shortage the required reaction time once a leak has been detected.

And in closing, thank you for taking the time to come down and listen to our public input and for making the first steps for controlling methane and protecting U.S. citizens against dangerous emissions from oil and gas sources. Thank you

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more detail regarding time for repair of components with fugitive emissions.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 96

Comment: We believe that the proposed leak detection and repair schedule is not sufficiently frequent. The proposed rule would allow decreased monitoring based on a leakage rate of less than 1 percent. We are strongly concerned that this creates a disincentive on industry to monitor for and repair leaks. And -- and therefore a fixed quarterly monitoring schedule is more appropriate, particularly given that the literature indicates that the occurrence of leaks is neither systematic nor necessarily predictable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 213

Comment: Also, leak inspections should be mandatory on a fixed monthly or quarterly basis.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 41

Comment: Second, the EPA's proposed protection and repair standard for well sites with compressor stations are inadequate because they allow for too much time between inspections and exempt operators from inspections based on past results. In fact, leaks are random and unpredictable, and the fact that a source is not leaking today, doesn't mean it won't leak tomorrow.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 21

Comment: In the proposed NSPS, EPA proposes that if fugitive emissions are detected from three percent or more of the fugitive emission components during two consecutive semiannual monitoring surveys with OGI, then the monitoring survey frequency for that compressor station must be increased to quarterly, while if fugitive emissions are detected from less than one percent of the fugitive emission components at the station, then the monitoring survey frequency for that well site may be reduced to annually. We request that EPA use a fixed survey time period, rather than varying periods based on performance, in the final rule. While we understand that EPA intends to reward operators with better compliance records under the current approach, in reality the constantly shifting time periods would only add to their administrative burden. Shifting time periods create addition administrative burdens by requiring operators to repeatedly calculate the number of leaks, and then adjust their compliance schedules accordingly for a large number of separate facilities. Because our business also involves adding or removing equipment from service, it becomes even more difficult for companies like ours to keep track of the exact number of fugitive emissions components at a facility at any given time, and thus the percentage of equipment that had leaks during each survey. Our compliance personnel would spend a large amount of time making and updating these calculations and those efforts would do nothing to reduce the methane emissions from any facility.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 129

Comment: API Opposes Performance-Based Frequency. EPA solicited comment on whether a performance-based frequency or a fixed frequency is more appropriate. API does not support a performance based frequency that is currently specified in §60.5397a(h) and (i). Tracking sites based on performance criteria is unnecessary and complex. A fixed annual frequency is sufficient for detecting and repairing leaks, as indicated in Section 27.3.9, and simplifies compliance. API members find that recurring LDAR has a diminishing return. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 20

Comment: USEPA solicits comment on whether a performance-based frequency or a fixed frequency is more appropriate with regard to LDAR. Antero recommends that a fixed frequency LDAR program be established because it would provide the regulated community with consistent requirements, and less onerous recordkeeping. LDAR programs using appropriate technology for confirmation of leaks according to a fixed-frequency will result in better LDAR outcomes than a performance-based program. According to USEPA's *Leak Detection and Repair, a Best Practices Guide,*

> "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions. To ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time, implement a plan for more frequent monitoring for components that contribute most to equipment leak emissions." (EPA-305-0-07-001, October 2007).

Performance-based (component count) programs are expensive to implement and maintain. Further, these counts may not provide reliable data. Component counts vary between well sites and in Antero's experience; the number of component s does not necessarily affect the site's actual fugitive emissions. USEPA's April 2014, *Report for Oil and Natural Gas Sector Leaks* (White Paper, page 54) concluded that component counts do not correlate with the magnitude of VOC emissions:

> Several studies suggest that the majority of methane and VOC emissions from leaks come from a minority of components (CL [Carbon Limits], 2013; Clearstone, 2002; and Clearstone, 2006). Furthermore, one study concludes that the majority of methane and VOC emissions from leaks come from a minority of sites (CL, 2013). One study found that the majority of leak emissions from these sites might be attributed to maintenance-related issues such as open thief hatches, failed pressure relief valves, or stuck dump valves (Thoma, 2012).

A program based on a fixed-frequency, which could vary depending on the type of component (e.g., a subset of "fugitive emissions components" that have consistently been found across the industry to be the source of the majority of fugitive emissions under normal operating conditions may be monitored on a more frequent basis) will be easier to implement, administer, and achieve better outcomes than performance-based programs. Fluctuating monitoring frequencies associated with performance-based programs are confusing and burdensome.

Antero requests consistency of inspection and monitoring frequencies for all well site affected equipment and emission components and suggests that an annual screening survey of well site affected equipment and emission components combined with semi-annual "primary component emitters" measurements should be developed. Under this scenario, the initial survey should take place as suggested below, and, if repairs are technically infeasible without a shutdown or if, as is provided in proposed § 60.5416a(b)(10) for closed vent systems, it is determined that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, the component should be placed on the delay of repair list and repaired by the end of the next shutdown.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See sections VI.F.1.e and VI.F.2.d of the preamble to the final rule for more detail regarding time for repair of components with fugitive emissions.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 10

Comment: WBI Energy recommends a fixed frequency for conducting surveys of fugitive emission components. WBI Energy recommends surveys at compressor stations in the transmission and storage sector be conducted on an annual basis to be consistent with survey requirements in 40 CFR 98, Mandatory Greenhouse Gas Reporting, Subpart W, Petroleum and Natural Gas Systems (Subpart W).

§60.5397a(h) - Frequency of Compressor Station Monitoring Surveys

- See previous comments. WBI Energy recommends a fixed frequency for monitoring at compressor stations in the transmission and storage sector. WBI Energy recommends monitoring these facilities annually to be consistent with requirements in Subpart W.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency. See response to DCN EPA-HQ-OAR-2010-0505-6882, Excerpt 27, for a discussion on the overlap between subpart OOOOa and subpart W.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 34

Comment: [As stated, PIOGA believes that requiring semiannual LDAR surveys for affected facilities is excessive and believes that annual LDAR surveys are sufficient.] However, in the event that semiannual LDAR surveys become a requirement, PIOGA supports a performance based frequency of LDAR survey requirements over the proposed two successive semiannual surveys.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Darin Schroeder, David McCabe, Lesley Fleishman and Conrad Schneider
Commenter Affiliation: Clean Air Task Force et al.
Document Control Number: EPA-HQ-OAR-2010-0505-7062
Comment Excerpt Number: 43

Comment: Furthermore, EPA's proposed metric for determining adjusted frequency—the percentage of leaking components— is not an accurate predictor of a facility's emissions performance. At a conceptual level, if emissions from leaking components were homogenously distributed, the percentage of components leaking at a facility would be a good indicator of facility-level emissions. However, there is overwhelming evidence that leak emissions follow a skewed, highly-heterogeneous distribution, with a relatively few number of sources accounting for a large portion of emissions. See for example Figure 1 *supra*. Figure 5 below depicts one such distribution taken from Allen *et al.* (2013). In such circumstances, the percentage of leaking components will not accurately reflect emissions and should not be used to determine the frequency of LDAR survey requirements.

We empirically examined the effects of EPA's proposed 1 and 3 percent thresholds using data from the City of Fort Worth Study Air Quality Study, which includes both component level emissions information and site-level data. Figures 5 and 6 below show the results of this analysis. Figure 5 compares site-level emissions to the percentage of leaking components and demonstrates that the individual sites with the highest emissions fall below EPA's proposed 1 percent threshold. Figure 6 aggregates site-level emissions at each of these thresholds. Sites with less than 1 percent leaking components constituted over half of total emissions and over half of all sites. Conversely, there were no high-emitting sites with greater than 3 percent of their components leaking, and sites above a 3 percent threshold accounted for a small percentage of total emissions.

[Figure 5: Site Methane Emissions(lb per year) Versus Percent Leaking Components shows leaking components and site methane emissions from the City of Fort Worth Natural Gas Air Quality Study data, 2011 and states that "The highest percentages of leaking components do not occur at the sites is with the highest emissions", and Figure 6: Number of Sites versus Percent of Leaking Valves and Connectors Monitored per site (Method 21), shows distribution of leaking components for same study and states "Assuming a 2% threshold, sites with less than 2% leaking components constituted 90% of total emissions over 80% of all sites. Even at a 1% threshold, sites with less than 1% leaking components constituted over half of the total emissions and over half of all sites".

Data from operators collected as part of Colorado's LDAR program further support a fixed inspection requirement. Colorado's approach requires operators to inspect for leaks at all but the smallest sites on a fixed annual, quarterly, or monthly basis (depending on the facility's tanks emission potential). 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014). Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to Encana, "[our] experience shows leaks continued to be detected well into the established LDAR program." Encana's data shows that while the largest reductions in VOC emissions occur in the first year of an LDAR program, significant emission reductions are still being realized in subsequent years of the LDAR program – because leaks re-occur at facilities. This pattern was independently confirmed in supplementary analysis carried out by Carbon Limits on leak inspection data from a number of well production facilities and compressor stations. Carbon Limits found that inspectors continued to find leaks in repeat inspections on the same facility. Additionally, Carbon Limits found that the cost-effectiveness of the leak inspections, expressed in dollars per metric ton of VOC abatement, did not significantly rise over several years after regulations were put in place requiring LDAR at facilities in Alberta.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6876, Excerpt 12, regarding fixed frequency monitoring. See response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9, for a discussion on the determination of the monitoring frequency.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 11

Comment: Proposed fugitive monitoring, referenced on page 56638, column 2, under section G. Proposed Standards for Fugitive Emissions from Well Sites and Compressors, on well sites should not be at the same level as manned gas plants. Many "well sites" and compressor stations are remote and unmanned. The additional cost in terms of additional emissions (fugitive dust emissions, emissions from multiple vehicles, inspections crews repair crews) from multiple site surveys (i.e. initial, resurvey, equipment costs for multiple crews to cover larger areas and potential modifications) over a 12 month period should be considered. Laredo would propose that new remote or unmanned sites be required to have a maintenance plan requiring regular annual maintenance on primary fugitive components like pressure relief valves, thief hatches, and ENARDO valves and documentation of the maintenance.

Response: The EPA disagrees with the commenter, although we encourage all owners and operators to develop a regular maintenance program. We are aware that even remote well sites are routinely visited on at least a monthly basis to check on and maintain the process equipment, and we believe it likely that the same holds true for remote compressor stations.

We note that the fugitive emissions monitoring requirements for all affected facilities have been streamlined and timelines extended, which will benefit the owners and operators of remote, unmanned facilities. See sections VI.F.1 and VI.F.2 of the preamble for more information regarding the final requirements for monitoring fugitive emissions from well sites and compressor stations, respectively.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.

Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 26

Comment: Compressor stations are small, and a single person oversees the compliance of multiple stations within a region. As a result, it does not make sense to require operators to create a separate plan for each of these stations. Instead, EPA should allow operators to create regional plans. Enterprise recommends that EPA craft a final rule where operators created a short and general corporate plan. Operators would then create a more detailed area-wide plan designed to apply multiple specified locations based on the way in which such operators have already divided up oversight responsibilities within their businesses. EPA has allowed area-wide plans in other contexts, such as for Spill Prevention Control and Countermeasure ("SPCC") Plans. By following a similar approach here, EPA could achieve the same compliance goals without creating unnecessary burdens for the gathering and boosting, and transmission and storage, segment operators.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 62.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 177

Comment: In addition, EPA provided no provision for an area-wide monitoring plan. §60.5397a(b) requires that companies either have a corporate-wide fugitive monitoring plan or a site specific monitoring plan. EPA provides no other options such as area wide plans for an operations area or basin. However, the information required in each plan under §60.5397a(c) is so detailed and specific, it will make it very difficult to write a plan that covers the various pieces of information for each separate area such as:

Technique for determining fugitive emissions.

- The manufacturer and model number of the fugitive emissions detection equipment to be used. – Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures and timeframes for identifying and repairing fugitive equipment components from which fugitive emissions are detected. This will vary based on whether leak detection is done internally or by a contractor and by area.
- Procedures and timeframes for verifying fugitive emission component repairs. This will vary based on whether leak detection is done internally or by a contractor and by area
- Verification of the optical gas imaging equipment -Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures for determining the maximum view distance from the equipment – Each area may have different facility designs such as enclosed portions of the facility due to cold

weather and physical locations such as on sides of cliffs that could limit or constrain the viewing distances.

- Procedures for conducting surveys – May vary by area or whether it is being done by contractors or internally.
- Training and experience needed prior to performing surveys – May depend on the equipment being used or whether the surveys in the area are being done internally or by contractors.
- Procedures for calibration and maintenance – Will vary based on the various equipment used by the area or contractors.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may have no sites or only a few sites subject to NSPS OOOOa which may require a company to handle the program differently than in another part of the country where they are drilling 30 wells or more a year that would be subject to NSPS OOOOa.

The elements required in both plans are extensive, requiring a great amount of detail with no added benefit. EPA should not require both plans. Furthermore, it is unnecessary for the plan to require many of the detailed information EPA is requesting for the site specific plans since these are small, dispersed, unmanned well sites and compressor stations. EPA should allow companies to create area monitoring plans in place of site-specific plans or as an option for corporate wide plans. Proposed rule revisions to address these issues are provided in Section 27.3.11.

Recommended Rule Text Revisions Based On Comments In This Section

§60.5397a(b) You must develop a corporate-wide or area-wide fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations in accordance with paragraph (c) of this section.~~, and you must develop a site specific fugitive emissions monitoring plan specific to each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site-specific plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that covers the elements of both the corporate-wide and site-specific plans.~~

§60.5397a(c) Your corporate-wide or area-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) through (i) of this section.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (j) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

~~(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

(A) Your optical gas imaging equipment must be capable of ~~imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~

(B) Your optical gas imaging equipment must be capable of ~~imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~

(i)~~(iii)~~ Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(ii)~~(iv)~~ Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(iii)~~(v)~~ Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(iv)(~~vi~~) Training and experience needed prior to performing surveys.

(v)(~~vii~~) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

§60.5397a(d) Reserved ~~Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.~~

~~(1) Deviations from your master plan.~~

~~(2) Sitemap.~~

~~(3) Your plan must also include your defined walking path.~~ ~~The walking path must ensure that all fugitive emissions components are within sight of the path and must~~ account for interferences.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16. With respect to the elimination of specific requirements of the monitoring plan, we have reviewed the requirements and disagree with the commenter that these elements are not needed for the fugitive emissions monitoring plan. We agree with the commenter that there may be different options within certain elements of the monitoring plan for varying site, area, or equipment types or issues.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 16

Comment: EPA states that all fugitive components at a subject facility will be monitored. EPA also states in the footnote on page 56637, column 2, under section VIII G. 1. Fugitive Emissions from Well Sites that approximately 700 fugitive components are located at a typical well site facility. What is the process for documenting that each of the 700 components has been surveyed? For example, is it acceptable to look over an area of multiple components with OGI and if no sign of leaks is present they are considered inspected? Or must each component be identified and inspected?

Response: The EPA notes that the monitoring plan is used to describe how the monitoring survey will be performed. One requirement of the monitoring plan is for the owner or operator to document an observation path that allows the OGI operator to visualize all of the components that must be monitored. If the OGI operator uses the instrument following the requirements outlined in the monitoring plan, then this should ensure all components are visualized. See sections VI.F.1.h and VI.F.2.g of the preamble for more information regarding monitoring plans.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute

Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 134

Comment: Monitoring Each Fugitive Component for Emissions. §60.5397a(e) – EPA is requiring that "*Each monitoring survey shall observe each fugitive emissions component for fugitive emissions*." Having to look at each component with an OGI system is extremely time consuming. Furthermore, it is not necessary to look at each component for leaks with the OGI equipment. From a scan around the facility you should be able to easily see if there are any leaks, and then if there are, move in to identify the exact location of the leak. OGI does not work like M21 where you have to sniff each component to determine if it is leaking.

Also, it is not always feasible to look at each component. Several locations in the North have equipment inside buildings with components next to the wall making getting to each component with OGI equipment impossible. Here is an example of what the sites look like: [Figure 27-1 Picture of Equipment Building]

API recommends making this requirement more in line with how OGI equipment works and the fact that each component does not need to be scanned to require that each piece of equipment with fugitive monitoring components be observed. For instance, observe the separator or well head for leaking components

Response: The EPA disagrees with the commenter. We are aware of how Method 21 and OGI work. While we agree that it is not necessarily essential to approach each individual component with OGI, we do not agree that an instrument operator will be able to stand at the facility gate and take a quick scan of the facility to determine if there are fugitive emissions. While this may work in some instances, we do not believe that it is an effective survey method for most sources of fugitive emissions. We believe that it is imperative that each component be included in the field of view of the OGI instrument during the survey from an appropriate distance. However, this does not preclude the OGI operator from looking at multiple components simultaneously.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 29

Comment: In addition, each monitoring survey shall observe each fugitive emissions component for fugitive emissions. Noble's surveyors currently view every component for a limited amount of time, after a site-wide scan in completed. However, there are instances, such as in a separator house, where many fugitive components may be located in a confined space or housing. The operator will make every attempt to view each component, but due to the circumstances, may be limited to looking for leaks without being able to identify the source with the camera. In such cases, the operator would then employ an alternative method for leak detection, such as the bubble method. EPA's protocol does not account for such situations.

Response: The EPA agrees with the commenter that there are situations in which OGI technology cannot pinpoint the specific component that is leaking. In such situations, it is incumbent on the surveyor to identify the leaking component by whatever means are appropriate.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 5

Comment: The MSC strongly recommends the removal of the requirement for site-specific monitoring plans. A reasonable corporate monitoring plan will cover all necessary components without also requiring the costly and time consuming development of hundreds, if not thousands, of site-specific plans.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 62.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 13

Comment: It appears that EPA has taken requirements from regulations that apply to refineries and proposed it for upstream exploration and production operations. Refineries are very different from upstream oil and natural gas operations. Oil and natural gas operations are often located more remotely, individually smaller operations and not as complex as a refinery. Refineries are larger, more complex and centralized operations. Thus, EPA should not rely on the same regulatory strategies and requirements for the two different sectors.

The resulting requirements are too restrictive and onerous to be realistically applied to exploration and production operations. In fact, many refineries have opted to use Method 21, instead of the more complex requirements required by EPA. The value of the current plan requirements is also not evident and the Proposed Rule does not specify how a company will comply with the requirements. Finally, it is not evident that EPA evaluated the ongoing costs of maintaining and conforming to the monitoring plan requirements.

The proposed requirement to develop site-specific monitoring plans provides minimal if any emission reduction benefit and will require a significant amount of resources to complete and maintain. Given the growth in specific areas, we would need to add staff to assist in the generation of site-specific monitoring plans. These staff members would need to have similar qualifications to the monitoring staff since they would be required to understand the monitoring methods and operation of facilities in order to accurately develop the site-specific monitoring plans. It would be better to allow companies to use these valuable staff members to reduce leaks versus managing administrative paperwork.

The greatest resource allocation would come from the deviations from the site-specific monitoring plans that require a walking path. The deviations from the site walking path would often occur because of safety concerns at a site, like construction, loose gravel, standing water or ice, or other environmental obstructions. Each time a deviation from the plan occurs documentation will be required and again, this would happen often requiring additional resources that could otherwise be utilized for emission reducing activities.

As an operator, which is currently running LDAR programs in multiple fields and states and for the reasons stated above, we assert that an adequately trained staff is sufficient to conduct a compliant survey. This voids the need for site-specific monitoring plans, which would only add a paperwork burden and provide no additional emissions reduction or compliance benefit. Other states like Colorado have implemented successful LDAR regulatory programs without a requirement for a corporate or site-specific monitoring plan.

Instead of an overly prescriptive monitoring plan, EPA could require a compliance plan tailored to upstream operations. Such a compliance plan could emphasize the value of training survey operators on how to conduct a monitoring survey and operate OGI equipment.

Solution Anadarko proposes that EPA allow for an operator-developed “compliance plan" instead requiring a monitoring program. A compliance plan would allow for a strong training component to accomplish EPA's goals in a simplistic and appropriate manner. A compliance plan should detail how a company or asset area will implement the LDAR program, including the training component.

Response: The EPA is not relying on the same requirements for the oil and natural gas sector that it employed for the refinery sector. See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16, for information related to monitoring plans. With respect to comments related to the walking path requirements, we are revising the walking path terminology to observation path in order to clarify that our intent is focused on the field of view of the OGI instrument not the physical location of the OGI operator and/or instrument. We believe this terminology change will alleviate commenters concerns regarding the potentially overly prescriptive nature of the defined walking path with transient interferences, environmental obstructions, weather conditions and safety issues as noted by the commenter. In addition, see response to DCN EPA-HQ-OAR-2010-0505-6474, Excerpt 16, for the EPA’s response related to the requirement for survey walking paths.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 76

Comment: Finally, development of site-specific plans is simply unwieldy and unnecessary given the expected number of facilities that would be covered by these rules. EPA's projected number of affected facilities depends on whether EPA excludes low producing sites from fugitive emissions requirements. EPA currently supports excluding low production sites because they generally result in lower fugitive emissions and are owned and operated by small businesses. Thus, EPA's low-impact projections suggest that 14,000 facilities will be affected by 2020, and 86,000 facilities will be affected by 2025. High-impact projections suggest that 22,000 facilities will be affected by 2020, and 140,000 facilities will be affected by 2025.

In short, site-specific fugitive emissions monitoring plans are unnecessary, duplicative of existing requirements, and overly burdensome. Thus, Kinder Morgan proposes striking all of EPA's proposed Section 60.5397a from the Proposed NSPS OOOOa Rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 62.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 10

Comment: Recordkeeping for this rule is overly burdensome and drastically increases the cost of compliance with no emissions reduction benefit. The site specific plans are unnecessary as the standards for key inspection criteria (e.g. wind speed) would be outlined in the corporate wide plan. Additionally, the site specific plan could limit the opportunity for experienced operators to use the optical gas imagers in the most effective way possible as this could require deviating from the pre-defined walking path to account for wind, weather or background site conditions on the day of the survey. Companies would require significant additional recordkeeping, QA/QC and compliance assurance staff to comply with this rule. All of this additional cost will result in no additional emissions reductions. This requirement also provides a disincentive for companies to participate in EPA's voluntary Natural Gas STAR Methane Challenge as the paperwork burden and time spent surveying sites with little to no leaks could divert resources dedicated to programs at existing sources. Additionally, it is not clear whether EPA has the resources to review these reports. Please see ATTACHMENT B for suggestions on appropriate recordkeeping and camera use guidelines.

ATTACHMENT B

Upon reviewing the proposal for fugitive emissions monitoring and repair, and as noted in our comment letter, Chevron does not see any value in developing site specific plans. A corporate or area-wide plan can achieve equal emission reductions in a manner that is responsible, transparent and verifiable. Elements that could be included in such a plan are outlined below.

- Overall Procedure

    - Safety considerations for camera usage.
        - Plan should include manufacturer recommendations for usage

- Camera Use and Training
    - Requirements for training on the proper use of an optical gas imager or a hand held device
        - Equipment specific operating parameters: background, temperature differences and wind speeds

- Leak Identification Procedure
    - Ways to mark leaks that cannot be fixed during survey
    - Standard method to identify leak locations (tagging or photo, as appropriate)

- Monitoring Frequency
    - Frequency determined by prior experience of leak likelihood, OR required state/local regulation or permit condition.
    - Weather and other safety related travel restrictions should be considered when planning frequency

- Repair Procedures (example procedures that could be tailored for company-specific needs)
    - Make initial attempt to repair on-site if safe, and approved by operations.
        - Resurvey with camera while on-site if possible
    - If leak cannot be repaired during survey, mark leak and log into maintenance system with an initial repair attempt scheduled within 30 days, if shut-in is not required.
        - Resurvey with camera, handheld or soap solution
    - If the leak cannot be fixed with first attempt, tag it and mark it to be fixed during the next shut-in. Note in maintenance system that repair is delayed and the reason.

- Recordkeeping
    - Date leak was detected
    - Date of first attempt to repair
    - Date of successful repair of leak
    - Part type (valve, flange) and service (compression, wellhead)

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16, and sections VI.F.1.h and VI.F.2.g of the preamble to the final rule for information related to the final requirement for monitoring plans. See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, for the EPA's response related to slight variations in survey walking paths. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for further information related to reporting and recordkeeping.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 33

Comment: Proposed § 60.5420a(c)(15)(i) requires a fugitive emissions monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emission components at a compressor station, as required in § 60.5397a(a). As discussed below in our comments under Section III(a)(xiii)(Fugitive Emissions Monitoring Plan), there is no need for a site-specific plan; a corporate monitoring plan will suffice. In addition to the comments referenced above, consider the following examples of how a site-specific monitoring plan is superfluous and impractical:

- Corporate-wide monitoring plans must provide a procedure "for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained." 40 C.F.R. § 60.5397a(c)(7)(iii). Alliance members have found that maximum viewing distances vary from one individual camera operator to another. Therefore, the requirement to maintain a corporate wide maximum viewing distance under the fugitive emission control program is unreasonable and lacks the flexibility operators need to conduct effective and efficient fugitive emission surveys.
- Each site-specific monitoring plan must identify "[d]eviations from your master plan." 40 C.F.R. § 60.5397a(d)(1). The Alliance assumes EPA's reference to "master plan" is the required corporate-wide monitoring plan in § 60.5397a(c). The Alliance submits that identifying all deviations from the corporate-wide monitoring plan in each site-specific monitoring plan is burdensome for operators. Well sites vary from site-to-site and from basin-to-basin. Dependent on development plans, operators could reasonably drill hundreds to thousands of wells in a basin over several years. Each well site will have hundreds to thousands of fugitive emission components. Deviations may be inevitable and pointing out all the variations would be extremely difficult, if not impossible. This requirement is also duplicative in nature because each site-specific monitoring plan will already contain adequate details of the survey for that site. Pointing out where those details conflict with the "master plan" is unnecessary.

In 40 C.F.R. § 60.5397a(b)-(d), the proposed rule requires the development of both corporate and site-specific monitoring plans for fugitive emissions components. While we agree that a basic plan is a good idea, and many operators have their own plans, there is no need for a site-specific plan, particularly with the level of detail that EPA is proposing. Preparing such site-specific plans—particularly the requirements for creating a sitemap and defining walking paths which may need to change if a facility is modified—provide no added environmental value and would be excessively costly to develop and become cumbersome to maintain as a facility is modified in the future.

Developing a site-specific plan for fugitive emissions monitoring would be more burdensome than, for example, the development of a Spill Prevention, Control, and Countermeasure (SPCC) plan, and the fugitive emissions monitoring plan would require even more frequent revisions. Instead of overly burdensome, site-specific requirements, operators should be able to develop a field-wide plan, much as they do for an SPCC program. This will reduce administrative burdens that add no environmental benefit while providing a sufficient level of detail to determine that robust practices are in place.

Operators should be able to develop their own corporate plans as long as they contain the following basic elements:

1. Cost-effective frequency for conducting surveys.
2. Technique/method for determining fugitive emissions.
3. Procedures and timeframes for identifying and repairing leaks, including provisions for leaks that are unsafe to repair.
4. Procedures and timeframes for verifying leak repairs.
5. Recordkeeping and reporting requirements (as discussed above).

Anything beyond these requirements would be overly prescriptive.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16, and sections VI.F.1.h and VI.F.2.g of the preamble to the final rule for information related to the final requirement for monitoring plans and deviations from monitoring plans. See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, for the EPA's response related to the requirement for survey walking paths.

We note that viewing distance is an important component to monitoring with an OGI instrument. The ability of OGI to detect fugitive emissions is relative to distance between the detection equipment and the target fugitive source. However, we have chosen not to be prescriptive on the maximum viewing distance in the final rule. We believe the company is better suited to determine this distance based on their knowledge of the individual sites, terrain and OGI instrument. Based upon their knowledge of the instruments, individual sites and site conditions, the owner or operator should determine the maximum viewing distance and document it in the monitoring plan.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 8

Comment: Furthermore, the MSC recommends the removal of highly detailed corporate monitoring requirements that could serve as a disincentive for OGI LDAR programs, as well as those utilizing a future technology not currently available.

Response: The final rule requires owners or operators to develop a fugitive emission monitoring plan for well sites or compressor stations within a company-defined area instead of corporate-wide and site-specific monitoring plans. The EPA evaluated the proposed requirements for the monitoring plans in light of the comments received and finalized the requirements necessary to ensure that the fugitive monitoring program provides the maximum emissions reduction benefits with the least burden to the regulated community. See sections VI.F.1.h and VI.F2.g of the preamble to the final rule for more on the final requirements for monitoring plans.

See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for information on a pathway for emerging technologies

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Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 23

Comment: The proposed requirements for corporate-wide monitoring plans require information that may not be readily available to affected facilities.

The proposed rule includes information requirements that will not be achievable by affected facilities. Because, as noted, most operators will likely elect to use contractors to conduct their fugitive emissions surveys, information related to the make and model number of "fugitive emissions detection equipment" will not be readily available and could change based upon the contractor conducting a given survey.

Response: The EPA acknowledges that there may be situations in which an owner or operator who uses contractors to conduct monitoring surveys would not be able to specify in the monitoring plan the make and model number of the monitoring equipment that will be used. In such situations, the owner or operator would include in the monitoring plan an explanation of the circumstances, as much information as is readily available from the prospective contractors regarding this equipment and a commitment to document the make and model number of the detection equipment that was used for each survey in the annual compliance report.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 49

Comment: As discussed above, EPA should be adopting an alternative standard or alternative compliance demonstration mechanism that allows for corporate plans that have already been or will be developed to satisfy the requirements of the rule. In addition, TXOGA believes that the proposed unit by unit elements of the plan are onerous and need to be cut back. The use of corporate monitoring plans that achieve the overall objectives of the rule is far more appropriate and should be allowed.

Response: Regarding the comment that the EPA should be adopting an alternative standard or alternative compliance demonstration mechanism that allows for corporate plans, see response to DCN EPA-HQ-OAR-2010-0505-6857, Excerpt 35. Regarding the elements of the monitoring plan, see response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 13

Comment: EPA Must Simplify the Monitoring Plans for the LDAR Program

EPA's proposal includes detailed and complex requirements for corporate-wide and site-specific monitoring plans that go far beyond what is needed to ensure that operators will effectively monitor fugitive emissions. These requirements are extremely burdensome, yet will have very little impact on the quality of an operator's monitoring survey program. GPA is concerned that EPA failed to fully evaluate the complexity of this monitoring program or the incremental costs of many of the additional monitoring plan requirements.

To avoid unnecessary costs and burdens on operators of affected facilities, GPA urges EPA to simplify the monitoring plan requirements to focus on the intent of the proposed rule and to avoid all extraneous requirements including the site-specific plans. Specifically, to realize the goals of providing EPA with high quality information while mitigating unnecessary burdens on industry, GPA believes only the following elements should be addressed in a corporate monitoring plan:

• Whether a company survey team or contract service will conduct monitoring activities;

• The training that will be required for individuals conducting monitoring surveys;

• The individual or team that will oversee the implementation of the leak detection program and how they will ensure compliance with the program;

• How compliance records and reports will be kept and submitted; and

• How OGI camera verification records will be kept.

A monitoring plan that focuses only on these core issues will provide EPA with assurance that fugitive emissions monitoring will be conducted in accordance with the NSPS program without subjecting operators of affected facilities to additional, unnecessary administrative requirements. Further, focusing on these key elements will allow a company to develop area-specific monitoring programs, as program elements may vary between geographic and operational divisions. This allows for monitoring programs to be specific for the operational divisions which are accountable for compliance at the local level.

To implement such a monitoring program, GPA recommends the following changes to EPA's proposed regulations:

Timeframes. The proposed requirements in 40 C.F.R. §§ 60.5397a(c)(1), (c)(4), and (c)(5) require owners and operators to include in their monitoring plans detailed information for each affected facility for conducting surveys, repairing leaks, and verifying repairs. GPA does not believe it is necessary or appropriate to include additional details in a monitoring plan since the timeframes for monitoring are already incorporated directly into the proposed rule. Instead, the monitoring plan should simply communicate how a company manages the compliance program and how the compliance data will be made available in recordkeeping practices.

Delay of repair. The monitoring plan should communicate how the company will manage and track components on delay of repair for reasons specified in 40 C.F.R. § 60.5397a(j)(1).

Manufacturer and model number. Operators may change leak detection equipment periodically under an LDAR monitoring program. Operators should not be required to update their monitoring plans after such equipment changes as would be required by 40 C.F.R. § 60.5397a(c)(3). In addition, because different monitoring equipment may be used in different geographic and operational divisions, it is illogical to require the manufacturer and model number of fugitive emissions detection equipment in a corporate-wide monitoring plan. The monitoring plan should instead communicate the company's procedures for managing and storing equipment verification data.

Survey procedures should be covered by an appropriate training requirement. To simplify the monitoring plan process and ensure that LDAR monitoring programs are implemented effectively, GPA believes that all monitoring survey operators should be trained to conduct a survey. Requiring a training program could replace a number of EPA's proposed monitoring requirements including those in 40 C.F.R. §§ 60.5397a(c)(2), 60.5397a(c)(7)(ii), 60.5397a(c)(7)(iii), 60.5397a(c)(7)(iv), 60.5397a(c)(7)(v), 60.5397a(c)(7)(vi), and 60.5397a(c)(7)(vii). Eliminating these requirements in favor of a training program would dramatically simplify the monitoring plan. A training program should include vendor provided training programs or internal company training programs. Minimum requirements of a training program can be specified as including the elements in 40 C.F.R. §§ 60.5397a(c)(2), 60.5397a(c)(7)(ii), 60.5397a(c)(7)(iii), 60.5397a(c)(7)(iv), 60.5397a(c)(7)(v), 60.5397a(c)(7)(vi), and 60.5397a(c)(7)(vii).

Site-specific monitoring plan requirements. The proposed site-specific requirements in 40 C.F.R. § 60.5397a(d) are overly burdensome and have very little positive impact on the quality of a company's monitoring surveys. For example, it will take a significant amount of effort and resources for companies to create walking paths and develop a map for each well site and/or compressor station. Again, by including a requirement for survey operators to be trained, EPA can ensure that the survey operators have the necessary qualifications and training to effectively monitor each fugitive emissions component without a pre-approved plan or walking map. Thus, an operator training requirement, coupled with a "certification" that each monitoring survey was performed appropriately should be enough to confirm that each component was monitored, even without an onerous site-specific map.

Response: The EPA notes that owners and operators are not limited in what can be included in a monitoring plan. Owners and operators are encouraged to include all information necessary to perform effective monitoring surveys. We also note that if a one-time monitoring like-kind equipment change is necessary (e.g. different OGI instrument model with the same optical and detector platform or different Method 21 analyzer with same detector and detection sensitivity), the owner or operator may note this in the annual report. We do not expect the owner or operator to have to update the monitoring plan for a one-time like-kind change. To document the change, in the annual report, you must document the information required to be in the monitoring plan, insofar as it differs from the monitoring plan. For optical gas imaging, you must include the manufacturer and model number of the instrument, the initial verification and procedures for calibration and maintenance. If the leak detection equipment changes such as the specific requirements in the plan are not relevant such as a new OGI platform with a different detector, an upgrade to the OGI leak detection algorithm that requires less user interactions or leak identification algorithm, then the monitoring plan will have to be amended or annexed with the appropriate information to the new leak detection equipment. Additionally, if any of the following procedures are revised as a result of using a different instrument, you must document the revised procedures in the annual report: daily checks, determining maximum viewing distance, determining maximum wind speed, conducting surveys (including accounting for thermal background adverse monitoring conditions and dealing with interferences), necessary training and experience and the observation path. For Method 21, you must include verification that your instrument meets the requirements outlined in §5397a(c)(8)(i), and if revisions are necessary, procedure for conducting surveys.

See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16, for information related to monitoring plans. See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, for the EPA's response related to the requirement for survey walking paths. See response to DCN EPA-HQ-OAR-2010-0505-6754, Excerpt 13, for information on training programs.

Commenter Name: Douglas Jordan, Director Corporate Environmental Programs, V+ Resource Development
Commenter Affiliation: Southwestern Energy (SWN)
Document Control Number: EPA-HQ-OAR-2010-0505-6922
Comment Excerpt Number: 16

Comment: EPA's proposal includes detailed and complex requirements for corporate-wide and site-specific monitoring plans that go far beyond what is needed to ensure that operators will effectively monitor fugitive emissions. These requirements are extremely burdensome, yet will have very little impact on the quality of an operator's monitoring survey program, (e.g. maintaining a digital photo of each site with geographic coordinates). Furthermore the complexity of the plan requirements is anticipated to result in confusion during implementation and interpretive challenges in future agency inspection (e.g. a fugitive emissions surveyor following the defined walking path but proceeds clockwise instead of counter-clockwise could be deemed "non-compliant" even if the survey viewed each component appropriately).

We do understand that some of the provisions are intended to provide some level of assurance that the fugitive emissions survey operator is conducting the survey appropriately. However, we do not believe that the rules nor the "corporate-wide fugitive emissions monitoring plan" nor the "site-specific fugitive monitoring plan" need to be as specific as outlined (especially for a device like the OGI which is identified as being "user friendly").

Recommendations:

SWN recommends that the proposed rule be revised to remove the provisions of 60.5397a(b) through (i). The rules should be revised to reflect the core elements of an effective and implementable fugitive emissions monitoring program intended to identify and repair leaks with reasonable provisions such as:

(1) Definition of leak

a. Observation of a plume in an OGI instrument or comparable monitoring and measurement devices

b. Measurement reading above 10,000 ppm or 500 ppm with Method 21 or alternate monitoring or measurement devices.

(2) Frequency of fugitive emissions monitor surveys

a. Initial for new/modified well site and compressor stations

b. Annual for new/modified well site and compressor stations

(3) Timing of fugitive emissions surveys

a. Initial survey within 60 to 180 days of commencing operation

b. Annual surveys thereafter on a calendar cycle

(4) Leak Repair Requirements

a. First attempt within 5 days

b. Repair within 30 days

c. Resurvey within 30-60 days

d. Delay of Repair provisions

(5) Recordkeeping Requirements

a. Date and Location

b. Name of Operator/Contractor conducting the fugitive emissions survey

c. Type or types of fugitive emissions monitoring device (s) used in the survey

d. Identification of leak (i.e. valve, connector, prv, oel)

e. First attempt repair date

f. Final repair date

g. Date of repair resurvey

h. Reasons for delay of repair status

(6) Reporting Requirements

a. Annual reporting including

I. Number of well sites or compressor stations sites surveyed

1II. Number of leaks identified

III. Number of leaks repaired

IV. Number of leaks on Delay of Repair Status

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 8, and DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16, for information related to monitoring plans. See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, for the EPA's response related to the requirement for survey walking paths. See response to DCN EPA-HQ-OAR-2010-0505-6924, Excerpt 7, for information related to digital photographs. See DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4 regarding revision of initial compliance date.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 17

Comment: Will the agency be issuing guidance on the construction of a monitoring and repair plan with minimum items that each plan must require? For example, will the agency have guidance on how to "determine viewing distance, and determine the maximum wind speed" as stated on 56641, column 2, under section VIII G. 1. Fugitive Emissions from Well Sites? If the agency doesn't standardize this process the monitoring will be inconsistent from location to location and will be ineffective as well as adding emissions to the atmosphere.

Response: The EPA has no plans at this time to issue guidance on the preparation of monitoring plans for this rule. The requirements included in the final rule serve as a minimum outline of the information that must be included in a monitoring plan. We believe that product literature provided by OGI instrument providers, available commercial training classes and web-based training materials may afford operators with valuable information in preparing monitoring plans. We do not believe that lack of standardization through guidance will render the fugitive monitoring program ineffective. We believe that the requirements outlined in the final rule are enough to ensure that effective surveys are being performed.

Commenter Name: Jim Welty
Commenter Affiliation: Marcellus Shale Coalition
Document Control Number: EPA-HQ-OAR-2010-0505-6803
Comment Excerpt Number: 14

Comment: The MSC believes the determination of wind speed during LDAR inspections using OGI is unnecessary. We agree that the general weather conditions should be recorded, but responsibility must be given to the camera operator, such as with other monitoring devices, to determine when they cannot be accurately used.

Response: The EPA disagrees with the commenter. We are aware that higher wind speeds can greatly degrade the ability of an OGI instrument to visualize fugitive emissions. For this reason, we are requiring owners and operators to determine a maximum wind speed under which monitoring surveys can be performed. In order to demonstrate compliance with the monitoring plan, the wind speed at the time of the survey must be documented.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 13

Comment: <u>Monitoring Plan</u>

- EPA proposed that an operator ensure an adequate thermal background is present in order to view potential fugitive emissions.
    - While operators strive to accomplish this for every component, it is not always possible. At times, alternative practices must be employed to verify the location of the leak, such as a bubble test.

- EPA proposed that deviations from an operator's master plan be recorded.
    - Maintaining administrative records for each deviation from the master monitoring plan would be onerous in many circumstances, would require retention of large

volumes of data but provide no additional environmental benefit. This is a paper exercise which is runs completely counter to EPA's e-enterprise initiative.

Response: Regarding the comment that alternative practices must sometimes be used to verify the location of a leak, see response to DCN EPA-HQ-OAR-2010-0505-6852, Excerpt 29. Regarding the comment regarding records of deviations from the monitoring plan, see response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 23

Comment: Regarding the proposed requirement that owners and operators maintain digital photographs of required monitoring surveys being performed, we request that EPA clarify that the required "photograph" may include a video recording of the survey. We note that OGI equipment works in a way that is similar to a home video recording device, and as such retention of the survey video recording should satisfy EPA's requirement that a "photograph" of the survey be retained. It would be easier to simply retain the entire recording than it would be to take numerous separate photographs, and a video record would be a more accurate memorialization of the survey in any event.

Response: The EPA agrees with the commenter that an OGI video recording satisfies the requirement in the regulations for a “digital photograph.” We note, however, that there is no requirement to maintain photographs or a video of the entire survey. The owner or operator is only required to include one digital photograph of the survey being performed from the optical gas imaging camera with the coordinates embedded or included in the photograph. Additionally, for each fugitive emissions component that is not repaired during the initial survey, the owner or operator must either temporarily tag the component or take a digital photograph or video that clearly identifies the location of the component. See sections VI.F.1.h and VI.F.2.g for more information regarding this issue.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 15

Comment: EPA Should Provide Clear Requirements on the Maximum Distance from which Operators May Survey a Component for Fugitive Emissions. The sensitivity and ability of OGI to detect fugitive emissions is relative to distance between the detection equipment and the target fugitive source. However, the Proposed Rule does not define the maximum allowable distance between the OGI lens and the target component. Instead, the Proposed Rule only requires operators to submit fugitive monitoring plans that identify the protocols surveyors must follow to identify leaks. EPA must correct this by adding a maximum-distance requirement in the Proposed Rule.

Without a clear requirement, there is no way to assure that operators are deploying the detection equipment effectively. Further, without such a requirement, less scrupulous operators have a clear incentive to conduct the survey as far away from leaking components as possible. EPA must address this gap in the regulation and work with manufacturers of the equipment to establish clear requirements in the regulations to ensure that operators comply with a uniform distance requirement.

Similarly, EPA should retain the existing requirement that operators verify the detection limit of their OGI equipment. To the extent that EPA determines that a numeric ppm threshold is inappropriate for OGI technology, EPA should amend the final regulation to account for this change.

Response: We disagree with the commenter that the rule must specify a maximum viewing distance for OGI monitoring, and believe that the company should specify the maximum viewing distance in their monitoring plan. The company is better suited to determine this distance based on their knowledge of the individual sites, terrain and OGI instrument. Different OGI instruments may have larger detector arrays or the ability to optical zoom to different distances. In addition, as OGI technology evolves, the acceptable maximum distance may change. However, this distance will be reviewed by the compliance authority who will determine if this distance is appropriate.

The final rule includes minimum sensitivity requirements for OGI instruments and requirements that the owner or operator's monitoring plan include procedures for (1) a daily verification check of sensitivity, (2) determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained; (3) determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold; (4) how the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions; (5) how the operator will deal with adverse monitoring conditions, such as wind; and (6) how the operator will deal with interferences such as steam. We believe that the requirements of the final rule ensure that OGI monitoring for fugitive emissions will be carried out effectively.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 30

Comment: EPA proposed that site-specific monitoring plans must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.

◦This section would be onerous to implement. While a site map will ensure the operator understands the process and facility layout, the operator often will need to modify the walking path to accommodate local weather conditions, onsite activity, and other factors. While these planning documents are effective in establishing base procedures, the experienced operator needs the ability to make onsite modifications based on their pre-survey walk through to improve the effectiveness of the camera, without being burdened by onerous administrative recordkeeping requirements. This is an example of a protocol whose costs far exceed its environmental benefits.

The EPA proposal would require a sitemap for each facility. The operator's plan must also include the defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13 and sections VI.F1.h and VI.F.2.g of the preamble for information regarding this issue.

Commenter Name: Theresa Pugh
Commenter Affiliation: Interstate Natural Gas Association of America (INGAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6872
Comment Excerpt Number: 24

Comment: Survey Requirements Should Not Include Definition of a Walking Path.

The Proposed Rule requires a site-specific monitoring plan that includes a defined walking path. This is an ambiguous and unnecessary requirement, and more burdensome than leak monitoring programs required in other NSPS. The operator and survey team are responsible to ensure that all affected components are surveyed, as established by programs in existing regulations. The proposed requirement to identify and adhere to a defined walking path is unnecessary and should be removed from the rule.

Response: See sections VI.F1.h and VI.F.2.g of the preamble for information regarding this issue. Regarding the final requirements for monitoring plans, including the requirement to define walking paths, see response to DCN EPA-HQ-OAR-2010-0505-6803, Excerpt 8.

Regarding the assertion that it is unnecessary to adhere to the defined walking path, see response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 178

Comment: The proposed requirement for site-specific monitoring plans, including the requirement to specify a walking path for each site, is unnecessary and the requirements are onerous. Many times production areas do not have site maps developed for each site. Development of a sitemap would be solely for this rule. The cost of developing site maps for every site was not included in the cost evaluation for LDAR. Furthermore, the requirement to specify a walking path for each site is unnecessary for oil and natural gas well sites and compressor stations. The person conducting the survey must be trained and have the knowledge and ability to use the monitoring device.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, and sections VI.F1.h and VI.F.2.g of the preamble for information regarding this issue.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 34

Comment: Site-specific monitoring plans must "include your defined walking path." The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences." 40 C.F.R. § 60.5397a(d)(3). Operators conducting OGI surveys must respond to a number of variables out in the field. These variables include weather, adverse monitoring conditions (*e.g.*, wind, sky condition) and interferences (e.g., steam). Also, each operator representative may want to walk through a site differently. There are too many variables at each well site for operators to commit to a specific defined walking path for each survey.

Preparing such site-specific plans—particularly the requirements for creating a sitemap and defining walking paths which may need to change if a facility is modified—provide no added environmental value and would be excessively costly to develop and become cumbersome to maintain as a facility is modified in the future.

Response: See sections VI.F1.h and VI.F.2.g of the preamble for information regarding this issue and response to DCN EPA-HQ-OAR-2010-0505-6806 Excerpt 13..

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 30

Comment: Fugitive emissions monitoring plans

In 40 C.F.R. § 60.5397a(b)-(d), the proposed rule requires the development of both corporate and site-specific monitoring plans for fugitive emissions components. While we agree that a basic plan is a good idea, and many operators have their own plans, there is no need for a site-specific plan, particularly with the level of detail that EPA is proposing. Preparing such site-specific plans-particularly the requirements for creating a sitemap and defining walking paths which may need to change if a facility is modified-provide no added environmental value and would be excessively costly to develop and become cumbersome to maintain as a facility is modified in the future.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, and sections VI.F1.h and VI.F.2.g of the preamble for information regarding this issue.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 77

Comment: EPA does not need a site-map for each of these facilities—many of which are in fact small sources and for which only minor emissions improvements will be achieved.

Under the site-specific emissions plan, EPA proposes that each facility should have its own "walking path." By this, EPA seeks that for each facility, the company develop a path for completing the fugitive emissions survey that will be used each and every time by any individual conducting the survey. Based on experiences implementing leak detection programs, both under Subpart W, NSPS KKK and OOOO, and other relevant state rules Kinder Morgan does not agree that a walking path is either necessary or appropriate. Additionally, the requirement to have a walking path could also deter the applicability of utilizing innovative monitoring technologies. Simply stated, the order of the monitoring or whether the monitor turns left versus turns right on a given day is not important. What is important is that the required components are monitored.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, and sections VI.F1.h and VI.F.2.g of the preamble for information regarding monitoring plans and walking paths.

The EPA believes that it is important to allow for the adoption of new technologies where appropriate. See response to DCN EPA-HQ-OAR-2010-0505-6941, Excerpt 2, for more information on a pathway for emerging technologies.

Commenter Name: Andrew Casper
Commenter Affiliation: Colorado Oil & Gas Association (COGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6889
Comment Excerpt Number: 16

Comment: Lastly, because operators design, construct, and operate facilities differently, there is no one-size- fits-all investigative technique or monitoring plan that can account for facility changes (*e.g.*, equipment that is down) or daily activities. Given unique facility designs, safety concerns and considerations, and unanticipated modifications in facility design and construction, a requirement to provide and maintain a walking/monitoring plan should be removed from the federal requirement. It provides no environmental benefit and is an overreach. This is especially true given that not all deviations from a monitoring plan are material, nor do such deviations mean that the monitoring plan was not followed or otherwise ineffective. Instead of focusing on specifically defined visual paths, Colorado operators have identified training as the key to a successful program. Specifically, the monitoring plan should focus on training, so that when difficulties or unforeseen events arise, the plan can still be implemented successfully.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, and sections VI.F1.h and VI.F.2.g of the preamble for information regarding this issue.

4.10 Third Party Contractors

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 15

Comment: The identification of "Next Generation Compliance" considerations within the context of proposed Subpart OOOOa is not appropriate. When considered within the expansive scope of proposed Subpart OOOOa, PIOGA considers the third-party verification to be regulatory overreach by EPA. While PIOGA acknowledges the burden of demonstrating compliance is on the owner/operator, the proposed approach would require the owner/operator to retain an independent third-party auditor to verify that the fugitive emissions surveys, likely being conducted by contractors, are being completed correctly. PIOGA objects to third-party verification of the fugitive emissions surveys. Such an additional compliance program layer will add significant cost and complexity to already complex and demanding proposed requirements.

Response: The EPA appreciates all of the comments, insights, and recommendations concerning the proposed use of independent third-party auditors for verification of fugitive emissions monitoring programs. After considering all the comments received on this issue, we are not finalizing requirements for third-party audits of fugitive emissions monitoring programs. See sections V.N and VI.J of the preamble to the final rule and Chapter 11 of this response to comment document for more details regarding our Next Generation Compliance and Rule Effectiveness provisions in the final rule.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:01 PM; Public Hearing #2 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337-2
Comment Excerpt Number: 7

Comment: I'm here today because I'm most concerned about the provisions in both the Colorado regime and the EPA regulations for self-reporting by industry. My work with the OIG showed that self-reporting is notoriously unreliable unless there are controls to independently verify that self-reported industry information by a third party.

So I'm here to strongly urge that EPA specifically require that any self-reporting is verified by an independent credible source like the Office of Inspector General, or perhaps as an alternative, an independent contractor working for the EPA.

So that's the primary reason I'm here today, to urge that verification of industry self-reporting is talked about in these regulations. Be happy to answer any questions you might have. Okay. Thank you very much.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15. The EPA notes that the delegated air agency is still responsible for reviewing the information reported by owners and operators and following up with owners and operators on any issues.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:01 PM; Public Hearing #2 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 33

Comment: And the third party -- how do you say that -- that would not just have the reporting by the company itself, but to have a third party looking at this and someone that is very skeptical would be very beneficial.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15. The EPA notes that the delegated air agency is still responsible for reviewing the information reported by owners and operators and following up with owners and operators on any issues.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 35

Comment: Regarding fugitives monitoring, EPA states that it anticipates a structure whereby owners or operators are responsible for determining that the personnel who conduct fugitive emissions audits are competent and independent pursuant to specified criteria. We support this approach, and we are not aware of any need to prevent companies themselves from determining who will conduct required audits at company facilities. TPA does not support EPA's alternative approach, whereby auditors would be required to have accreditation from an auditing body and/or consensus standards and protocols would apply. It would simply add an additional regulatory layer to what should be a fairly straightforward process, and in any event there is no guarantee that better or more accurate results would be obtained simply because consensus standards and protocols were applied. In summary, we see no "problem" that needs to be fixed, and we believe that companies themselves should be allowed to determine and document that monitoring is being conducted in an appropriate manner.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 14

Comment: USEPA is requesting comments on audit programs to ensure that the collection of fugitive emissions components at well sites and compressor stations are properly managed. The existing proposal places the burden on facilities to determine and document that their auditors are "competent and independent pursuant to specified criteria." Antero supports that approach and believes that an "independent third-party" approach would be excessive and unworkable. USEPA's experience with the ineffective implementation of past LDAR programs may be in part associated with inherent design flaws of performance-based systems. A fixed-frequency LDAR program combining screening and measurement techniques, as discussed below, will negate the need for independent auditors.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15.

Commenter Name: Jeff Addington, Manager Air Quality
Commenter Affiliation: Archrock Services, L. P. and Archrock Partners Operating LLC ((individually and collectively, ArchRock)
Document Control Number: EPA-HQ-OAR-2010-0505-6944
Comment Excerpt Number: 10

Comment: As to verifying that repairs have been made, Archrock supports making the owner or operator of the compressor station responsible for determining and documenting such repairs. Companies should not be required to engage the services of a third-party auditor to verify such obligations have been fulfilled. If a third-party auditor was required, it would be even more logistically burdensome for service providers like Archrock who would need to have personnel present during any testing conducted on its equipment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15.

Commenter Name: C. Thomas Hallmark, Ph.D., Chairman, et al.
Commenter Affiliation: Texas Board of Professional Geoscientists (TBPG)
Document Control Number: EPA-HQ-OAR-2010-0505-5291
Comment Excerpt Number: 1

Comment: The Texas Board of Professional Geoscientists (TBPG) was created in 2001 to regulate the public practice of geoscience in Texas. Texas Occupations Code Chapter I 002 (the Act) provides for the requirement of licensure to offer or engage in the non-exempt public practice of geoscience in Texas. Section 1002.251 of the Act, states, "LICENSE REQUIRED (a)

Unless exempted by this chapter, a person may not engage in the public practice of geoscience unless the person holds a license issued under this chapter." Section 1002.251 of the Act, also states, "(c) A person may not take responsible charge of a geoscientific report of a geoscientific portion of a report required by municipal or county ordinance, state or federal law, state agency rule, or federal regulation that incorporates or is based on a geoscientific study or geoscientific data unless the person is licensed under this chapter."

The Texas Board of Professional Geoscientists licenses approximately 4,400 Professional Geoscientists. The requirements of licensure include: (1) be of good moral and ethical character as attested to by letters of reference submitted in behalf of the applicant, (2) have graduated from a course of study in a discipline of geoscience that consists of at least four years of study and includes at least 30 semester hours of credit in geoscience or satisfactorily completed other equivalent requirements, (3) have a documented record of at least five years of qualifying work experience that demonstrates that the person is qualified to assume responsible charge of geoscientific work, (4) pass an examination required by the board covering the fundamentals and practice of the appropriate discipline of geoscience, and (5) meet any other requirements established by the board.

The mission of the Texas Board of Professional Geoscientists is to protect public health, safety, welfare and the state's natural resources by ensuring only qualified persons carry out the public practice of geoscience and enforcing the Code of Professional Conduct the Board has established for its licensees.

Texas-licensed Professional Geoscientists provide services in the areas of environmental geology, hydrogeology, engineering geology, and other areas that must be performed competently and ethically to protect the public health, safety, welfare, and natural resources. Failure to perform these services competently and ethically can result in disciplinary action by the board up to and including revocation of licensure.

In the September 18, 2015, proposed rule titled Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, the EPA describes a number of options for ensuring fugitive emission verification. In section IX Implementation Improvements, part (B) Fugitive Emissions Verification, the EPA describes possibly allowing parties responsible for performing leak surveys to have a professional accreditation such as that provided by ANSI, ASTM, ISO or NIST. The TBPG would request that persons with Professional Geoscientist licensure be recognized as equal to a licensed Professional Engineer.

Specifically, Professional Geoscientists are licensed to ensure protection of human health and the environment and are subject to a licensure program. Professional Geoscientists' work products routinely include soil, water and vapor migration assessments and vapor monitoring for spills and releases. Licensed Professional Geoscientists have extensive experience that should be considered as an appropriate accreditation for the EPA's proposed rules.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum
Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 25

Comment: Third-Party verification, referenced on page 56648, column 2, under section X. A. Independent Third-Party Verification, will be difficult to implement when hiring contractors to perform the OGI surveys. The contracting company will not know the individual personnel nor the number of people that will be contracted to conducting the surveys. Those personnel will likely change throughout the year. EPA is asking that the auditor meet with each individual in the field conducting the survey. Given the likelihood of hundreds of surveys per year this does not appear to be a feasible requirement.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15.

Commenter Name: Richard A. Hyde, P.E., Executive Director
Commenter Affiliation: Texas Commission of Environmental Quality (TCEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6753
Comment Excerpt Number: 4

Comment: Independent third-party verification of fugitive emissions monitoring program. The TCEQ is not opposed to the EPA allowing voluntary independent third-party verification of fugitive emissions monitoring programs as an additional resource to support compliance. However, this voluntary use of third parties should be a decision of the company involved. The TCEQ does not support an additional, mandatory regulatory layer of third parties to support compliance in this context. The TCEQ provides comments below on optical gas imaging (OGI) instrument use, operator training and skill, and OGI emission quantification. TCEQ also requests that the EPA provide further guidance as outlined below. The EPA should establish and maintain a register of qualified individuals or companies available to perform third-party verification for fugitive monitoring compliance. The TCEQ opposes any imposition of complex audits or rules for audits with which companies will have to comply.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 52

Comment: EPA solicits comment on establishing third-party verification of the required fugitive emissions monitoring program, though this is not included in the proposed rule regulatory provisions. According to the preamble, the third-party audit program would provide a structure in which the facilities themselves are responsible for determining and documenting that their auditors are "competent, independent, and accredited, apply clear and objective criteria to their design plan reviews, and report appropriate information to regulators." EPA also requests comment on one or more alternative approaches, such as "requiring auditors to have accreditation from a recognized auditing body or EPA, or other potentially relevant and applicable consensus standards and protocols." EPA also states that there would be a need for a mechanism "to ensure regular and effective oversight of third-party reviewers by the EPA and/or states which may include public disclosure of information concerning the third parties and their performance and determinations, such as licensing or registration."

EPA postulates that a third-party audit program would provide verification to a regulator that a regulated entity is meeting one or more of its compliance obligations such that the regulator could give "significant weight to the third-party verification provided in the context of a regulatory program with effective standards, procedures, transparency and oversight." Specifically, EPA states that "[w]hile requiring regulated entities to monitor and report should improve compliance by establishing minimum requirements for a regulated entity's employees and managers, well-structured third-party compliance monitoring and reporting may further improve compliance."

EPA's premise that third-party audits will improve compliance is a mere assertion that is not supported in the record. While it may be true that audits improve compliance, EPA has not supported the conclusion that third party audits increase compliance. What is indisputable is that a third-party audit requirement will dramatically increase the costs of the program. Indeed, expensive, consultant-driven audits will have a negative competitive impact on smaller, less funded operators in an already-competitive industry with declining oil and gas prices. Any approach should recognize that audits will already strain available resources and that third party auditing requirements will potentially threaten viability of some operators without a corresponding increase in compliance. Any requirement for third-party audits will need to demonstrate that there is a quantifiable increase in emissions reductions that is justified based on a cost-effectiveness analysis.

Because EPA has also failed to include in the proposal an analysis of the cost of a third-party verification system or any proposed regulatory provisions, a third-party audit program cannot be included in the final rule. As discussed above in Section III(G), supra, commenters cannot evaluate based on the information EPA has provided the costs of a third party audit program or the regulatory and compliance implications of such a program. The proposal does not provide adequate notice of the requirements because it contains no details regarding how the verification system would work. Thus, commenters are unable to provide meaningful comment on the scope of the program, estimated cost levels, workability, and other factors that would need to be considered. EPA has failed to demonstrate the benefit to using third-party verifiers, or provide an analysis of associated cost and impacts, thus the record does not support including such a requirement in the final rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6943, Excerpt 15.

4.11 Recordkeeping

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 20

Comment: Currently, there are only two manufacturers of OGI cameras. Only FLIR has the capability to embed latitude and longitude within the photograph. Concho requests that instead of requiring latitude and longitude be embedded, that the EPA instead allow an operator to photograph the battery or well identification sign which includes the legal description. This will still provide the EPA with the location of the site while not favoring a specific vendor.

Response: As an alternative to embedded coordinates from the optical gas imaging instrument, we have revised the final rule to also allow a digital photograph of the survey that includes a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the image.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 14

Comment:

- The EPA protocol would require the operator to maintain records of ambient temperature, sky conditions, and maximum wind speed at the time of the survey.
  - While horizontal wind shear impacts leak detection, the EPA's proposed requirement suggests that wind speed must be monitored continuously during the survey and the highest wind speed needs to be reported. As noted previously, an operator needs to have the ability to temporarily suspend the survey during wind gusts. This section would require the operator to report that value even if the survey was suspended and the components re-surveyed at a lower wind speed.
- EPA also proposes that the operator must record any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
  - A trained and experienced operator may modify the monitoring plan to optimize the effectiveness of the camera. Minor modifications to the monitoring plan to mitigate onsite conditions that do not impact the camera's detection ability should be allowed without onerous recordkeeping requirements.
- In addition, EPA proposes that the operator retain one or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an

alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

- There are few cameras available on the market that meet these requirements. The intent of this section is to create records confirming that the operator was indeed onsite conducting the inspection. Currently, Noble's data collection software has the ability to capture latitude/longitude locations (minus the photograph). Additionally, Noble and many other operators utilize Cartasite or similar vehicle monitoring software that shows date/time/location information that could document the same type of information using current data management workflows without the introduction of additional non-intrinsically safe devices to the work site.

Response: The EPA disagrees that the final rule would require the owner/operator to report wind speeds that are recorded outside the time that monitoring was performed. The final rule requires the owner/operator to report "ambient temperature, sky conditions, and maximum wind speed at the time of the survey" (40 CFR § 60.5420a(b)(7)(iv)). Wind gusts when a survey has been suspended need not be included in the maximum wind speed determination.

We fully expect a trained and experienced camera operator to know when deviations from the standard monitoring plan are necessary, and we expect operators to make these deviations as needed in order to conduct effective surveys. We agree that the deviations may not impact the camera's detection ability and note that the deviations can actually improve the detection ability. However, this does not mean that deviations from the monitoring plan should not be noted. The record provides valuable information to air agency reviewers on how surveys are conducted. It allows air agencies to determine if deviations from the monitoring plan are adequate and warranted. And information on deviations from standard practices can even lead to future development of best practices procedures.

We believe that all owners and operators will be able to comply with at least one of the alternatives for digital photographs. This requirement is necessary to ensure compliance and is not overly burdensome for owners and operators. While the commenter states that many operators use vehicle monitoring software to document locations, this information does not document that a survey was actually performed, only that the operator was at the site. We do not believe that this is adequate compliance assurance that a survey was conducted, and as such, we have retained requirements for digital photographs in the final rule.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 146

Comment: 27.6.6 Recommended Text Revisions Associated With Reporting and Recordkeeping Requirements.

§60.5397a(k)(6)(ii) ~~One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

§60.5420a(b)(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station <u>or central production site for a corporation or area</u>, the records of each monitoring survey conducted during the year:

(i) <u>The number of facilities inspected</u>

(ii) <u>The total number of inspections</u>

(iii) <u>The total number of leaks identified broken out by component type</u>

(iv) <u>The total number of leaks repaired</u>

(v) <u>The total number of leaks on the delay of repair list as of December 31st</u>

~~(i) Date of the survey.~~

~~(ii) Beginning and end time of the survey.~~

~~(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.~~

~~(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(v) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~

~~(vi) Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section~~

~~(A) Location.~~

~~(B) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As~~

~~an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

~~(C) The date of successful repair of the fugitive emissions component.~~

~~(D) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

§60.5420a(c)(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) and (ii) of this section.

(i) ~~The fugitive emissions~~ The corporate-wide or area-wide monitoring plan ~~for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5397a(a~~).

(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (F) of this section.

(A) Date of the survey.

(B) Location of the survey

(C) A list of leaking components

(D) The date of the first attempt to repair and additional attempts to repair

(E) The date the leak was repaired

(F) The delay of repair list including the basis for placing leaks on the list

(G) The date the leak was remonitored to verify the effectiveness of the repair

~~(B) Beginning and end time of the survey.~~

~~(C) Name of operator(s) performing survey. You must note the training and experience of the operator.~~

~~(D) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(E) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~

~~(F) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(1) through (2) of this section.~~

~~(1) Location.~~

~~(2) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

~~(3) The date of successful repair of the fugitive emission component.~~

~~(4) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

Response: While the EPA has made some changes to the recordkeeping and reporting in the final rule, we do not agree with the majority of the changes recommended by the commenter. Recordkeeping and reporting are vital components of compliance assurance. We believe that the information that we are requiring owners and operators to document are necessary in order to determine how and the conditions under which the surveys are performed in order to determine whether owners and operators are performing surveys effectively. Records also provide information on the fugitive emissions that exist at the facility on an ongoing basis and whether owners and operators are in compliance with the repair obligations in the final rule. Because delegated agencies are unable to visit all regulated sites, reporting information is a necessary part of ensuring compliance. While we do not believe it is necessary to report all of the data recorded during the survey, we do believe that it is imperative to report data that allows a delegated agency to determine whether further review of records is necessary.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 37

Comment: The final reporting requirement should require only what is reasonable to collect and report based on an assessment of what information is necessary to demonstrate compliance (not necessarily, what information can possibly be collected). States like Colorado, Wyoming, and Utah are well ahead of EPA in this respect, and EPA should look to these reporting programs as models. The annual report should be a summary of monitoring surveys for the reporting period and not merely a collation and submission of all the recordkeeping requirements. Considering the voluminous amount of records, this would be a very onerous, time-consuming, and excessive task. Moreover, the rule does not justify how the proposed detailed and burdensome reporting requirements provide any environmental benefit. In particular, the report need not include items specified in proposed § 60.5420a(7) for each monitoring survey; these are items that should be kept as records, available for EPA review, but not included in the annual report.

In line with what Colorado Regulation 7 requires in Section XVII.F.9 for annual LDAR reporting, we recommend that only the following elements be part of the annual report for fugitives:

1. The number of facilities inspected
2. The total number of inspections
3. The total number of leaks identified, broken out by component type
4. The total number of leaks repaired
5. The number of leaks on the delayed repair list as of the end of the reporting period

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 39

Comment: In addition, the proposed rule does not define the format of the report making it difficult to assess how the data should be collected, stored, and reviewed for quality. We recommend EPA keep the reporting as simple as possible.

Response: In the final rule, as was proposed, the fugitive emissions information is documented in the annual report. §60.5420a(b)(11) requires the annual report to be submitted electronically through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) in the Central Data Exchange.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 40

Comment: Finally, 40 C.F.R. § 60.5420a(b)(1)(i) requires annual reports to include the address of the affected facility. Typically well sites and even compressor stations do not have physical addresses. In lieu of the address, we recommend that EPA use the latitude and longitude of the well site or compressor station for reporting purposes.

Response: The EPA is sensitive to the fact that due to the remote nature of some well sites and compressor stations, a "street address" may not be assigned to these sites. However, when annual reports are submitted electronically via CEDRI, the system requires the address field to be completed. Although an entry in this field has to be made, the system does not require it to be a traditional numerical street address. Owners or operators may enter a descriptor of the site location, such as "State Road 1007, Mile Marker 83." Where an address is not available for the site, the owner or operator must also report the latitude and longitude of the site.

Commenter Name: Jeff Addington, Manager Air Quality
Commenter Affiliation: Archrock Services, L. P. and Archrock Partners Operating LLC ((individually and collectively, ArchRock)
Document Control Number: EPA-HQ-OAR-2010-0505-6944
Comment Excerpt Number: 9

Comment: Although not applicable to service providers like Archrock when they are not the owner or operator of the compressor station, we note that the recordkeeping and reporting requirements raise potential public safety considerations. For example, maintaining operational data onsite at a remote location may make such information vulnerable to vandalism and/or theft. Additionally, providing EPA with copies of data that provide the GPS coordinates of these compressor stations would make such data available to the general public, including anyone intent on causing physical harm to the facility, obtaining competitive corporate operational data or otherwise. Finally, instituting a requirement to retain such data onsite or to provide copies of the same to EPA might encourage the general public to try to access such facilities, which could pose safety issues and security issues directly impactful to the natural gas transportation infrastructure system. Only properly trained personnel should access such locations due to the potential hazards and risks associated with the operation of equipment in the oil and gas industry. Archrock advocates a system that would entail providing EPA the ability to inspect the data without retaining copies.

Response: The EPA notes that owners and operators are not necessarily required to keep records onsite; these records can be kept at the nearest field office, which is usually a manned location. The EPA and air agencies generally require site identification information both in reporting and permitting applications so that regulators know where the sites are located. We also note that location information is often already easy to access on the internet. For example, the website for the Railroad Commission of Texas has interactive mapping of all oil and gas wells in the state of Texas. The North Dakota Department of Mineral Resources has a similar interactive mapping program.

We do not believe that providing information to the EPA encourages the general public to access oil and gas sites, as the general public would still be subject to accountability under both federal and state laws, including laws against trespassing on private property. We agree that only properly trained personnel and other persons authorized by the owner of the site should access any site.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 56

Comment: We believe that the owner/operators should maintain all of the inspection records at their facility and be available for EPA to perform audits of the records. This is the simplest and lowest cost method for both owners/operators and EPA. Involving third-party organizations increases cost and communication time between owners/operators and EPA.

If a simple audit system is implemented in the final regulation, the owners and operators will strive to maintain compliance as an incentive to continue utilizing the simple audit system without uploading all of the documentation to EPA. As the verification system complexity and cost increases, neither the owners/operators nor EPA benefit from the additional complexity added to ensure compliance is being achieved.

During EPA's audits of our systems or facilities, EPA can validate that all new or modified sites meet the regulatory requirements of the proposed regulation. Digital photographs, equipment invoices (or post cards, as referred to on Page 333), permitting records, geologic reports, or production data will be available for review to demonstrate compliance. Owners/operators will have this information available for wells that have been drilled or modified and meet the compliance requirements.

We request that the final regulation posted in the Federal Register provide clear criteria for EPA's audits (i.e., specific documentation required, digital photographs, OGI images, gas or oil flow rates...). We believe that the audits and personal interactions with EPA will meet EPA's requirements to ensure compliance while minimizing the documentation and simplify the reporting process. We also believe that EPA and owners/operators working together during the audits will build beneficial relationships between regulators and industry as we strive to achieve common goals.

EPA has requested input on the appropriate frequency, actions, trends or compliance triggers which might require or allow deviation from the audit frequency. We recommend that flexibility be built into the final regulation to recognize that companies are occasionally forced to deal with major interruptions to their business that are uncontrolled or unexpected. These interruptions may be a result of a fire, hurricane, earth quake, flooding, or other major event. EPA may consider including exemptions for these types of events into the audit and reporting frequencies.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)

Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 13

Comment: Fugitive Emission Monitoring. EPA is proposing in § 60.5397a(k)(6)(ii) that an owner or operator maintain documentation of each source of fugitive emissions (i.e., fugitive emissions component) one or more digital photographs of each required monitoring survey being performed. However, the proposed regulation does not specify if optical gas imaging equipment should be used for the digital photographs - a digital image from any camera could be used as documentation of fugitive emissions. The DEP recommends that EPA clarify in the final rule if an optical imaging camera should be used for digital photographs to document each source of fugitive emissions.

The DEP's permitting criteria require the owner or operator of well sites and natural gas compression facilities to maintain records of only leaking components by taking digital photographs using an optical imaging camera. The photographs must be imbedded with date, longitude and latitude information followed by another digital photograph of the same component after it has been repaired to assure that the component was repaired within 15 days. Therefore, DEP recommends that EPA require the owner or operator to maintain records of only leaking components by taking digital photographs imbedded with the date, longitude and latitude information. The final rule must also explicitly require that the digital photographs be taken using an optical imaging camera.

Response: The EPA notes that the owner or operator must include one or more digital photographs of the survey being performed from the optical gas imaging camera with the coordinates embedded or included in the photograph. We note that the OGI instruments embed the latitude and longitude of the instrument, not the component being surveyed. We have added to the recordkeeping section to indicate that for each fugitive emissions component that is not repaired during the initial survey, the owner or operator must either temporarily tag the component or take a digital photograph or video that clearly identifies the location of the component (e.g., by using site landmarks). However, there is nothing to prevent the owner or operator from using the OGI instrument to provide this documentation, which would satisfy the requirements of subpart OOOOa, as well as the requirements outlined by the commenter. See section VI.F.1.h. of the preamble to the final rule for further discussion.

Commenter Name: John Quigley
Commenter Affiliation: Pennsylvania Department of Environmental Protection (DEP)
Document Control Number: EPA-HQ-OAR-2010-0505-6800
Comment Excerpt Number: 15

Comment: Delay of Repair. EPA has proposed that the repair of a closed vent system or cover may be delayed for leaks or defects if the repair is technically infeasible without a shutdown, or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. As proposed, the repair of the equipment must be completed by the end of the next shutdown.

While DEP recognizes that delays in the repair of equipment may be necessary, the proposal allows leaks to continue indefinitely at an owner or operator's discretion until the next shutdown. At a minimum, the final rule should require an owner or operator to provide notice of the next scheduled shutdown to State and local agencies if leaks are not repaired within 15 calendar days after detection. The notice should also include the anticipated repair date. Records concerning leaks, repair methods, repair dates, and shutdowns should be recorded and maintained for at least five years.

Response: A delay of repair for fugitive emission components is provided to prevent excessive emissions from occurring due to an unscheduled shutdown of a well site or compressor stations. Emissions from an unscheduled shutdown that would occur in order to repair a fugitive emissions component could be greater than the fugitive emissions resulting from a delay of repair. Therefore, we have included provisions for a delay of repair for these components that requires the components to be repaired during the next shutdown, well shut-in or shutdown, or within two years of finding the fugitive emissions, whichever is earlier. Operators must list components that are on delay of repair and provide an explanation in their annual report. We believe that this provide the appropriate information to the state or local agencies. See response to DCN EPA-HQ-OAR-2010-0505-5418, Excerpt 8 for more information. Also see section VI.F.1. of the preamble to the final rule for further discussion.

Commenter Name: J. E. Rosenberg
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6887
Comment Excerpt Number: 3

Comment: LDAR results must be public.

The requirement for operators to inspect for leaks using Optical Gas Imaging (OGI) is commendable. It may come as a surprise to EPA to learn that informed citizens are aware of FLIR technology and doing what we can to raise awareness on this issue. Clearly, an important goal of EPA, over and above all of the technicalities and acronyms and jargon and legalistic language, is to instill a basic operating culture in the Oil & Gas Industry: keep it in the pipes! This will really only work if the public can be involved in having our own access to the evidence that when leaks occur, they are fixed. Seeing is believing. That is the whole point of OGI. The proposed rule should be amended to require transmission to their permitting authority all operator OGI footage, with a clear stipulation that this footage will be available to the public via a Right To Know or FOIA process.

Response: All information collected in the annual report will be publically available; however, we do not require that the operator report all OGI data that is recorded nor do we require the operator to retain records of an entire survey. We agree that recordkeeping and reporting are vital components of compliance assurance. We believe that the information that we are requiring owners and operators to document are necessary in order to determine that a survey was performed, how the survey was performed and the conditions under which the surveys are performed in order to determine whether owners and operators are performing surveys effectively. Records also provide information on the fugitive emissions that exist at the facility on an ongoing basis and whether owners and operators are in compliance with the repair obligations in the final rule. While we do not believe it is necessary to report all of the data recorded during the survey, we do believe that it is imperative to report data that allows a delegated agency to determine whether further review of records is necessary. We believe that the final rule captures the necessary information in the annual report.

Commenter Name: J. E. Rosenberg
Commenter Affiliation: Citizen
Document Control Number: EPA-HQ-OAR-2010-0505-6887
Comment Excerpt Number: 4

Comment: Concern with LDAR is laudable but insufficient. Air quality permits must also include blowdowns, malfunctions and other uncontrolled releases.

EPA's attention to the climate implications of methane emissions from Oil & Gas extraction and transportation — as evidenced in this proposed rule — is admirable. However, from the point of view of implications for climate change, to put it crudely, the atmosphere doesn't care why emissions happened; emissions are emissions, whether they happen due to poor maintenance of machines that run every day, inoperable control devices, leaks, intentional pressure relief, human error, or any form of preventable malfunction. Blowdowns are particularly notable, since a certain number of blowdowns in a given time period can be foreseen. In fact, some blowdowns are so foreseeable that they are actually scheduled in advance. All blowdowns and other uncontrolled releases must be logged, and transmitted to the permitting authority within only a few days (which EPA should specify). In my state, Pennsylvania, PA-DEP imposes a requirement for operators to log blowdowns, but only to transmit that information to PA-DEP on request. If blowdown logs are not requested by PA-DEP, they remain in the hands of the operator, which is presumably a private party, and are therefore not public records. All blowdown logs must become public records, where they can be reconciled by the public against "inventories" of emissions, and reconciled against amounts permitted to emit. Applicants for Air Quality permits must be instructed to include itemized blowdown estimates in PTE calculations, and the permitting authority should evaluate whether those are reasonable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6800, Excerpt 17, in Chapter 15 of this document.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 21

Comment: §60.5420a(b)(7) - Reporting Requirements for Fugitive Emissions Monitoring

WBI Energy recommends establishing a deadline on an annual basis for submitting the annual reports required by the rule. As currently written, subsequent annual reports must be submitted no later than same date each year as the initial annual report. This results in each facility subject to the rule having different submittal dates for the annual report. As Subpart W sets a deadline of March 31st of each year for filing annual reports, WBI Energy recommends setting an annual deadline for submittal of reports for this subpart.

Response: In §60.5420a(b) of the final rule, we have provided that, "Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period." We believe this provision provides adequate flexibility for choosing a date for submitting the annual report.

Commenter Name: Eric Schaeffer, Sparsh Khandeshi and Adam Kron, Environmental Integrity Project (EIP) on behalf of Adrian Shelley III, Executive Director,
Commenter Affiliation: Air Alliance Houston et al.
Document Control Number: EPA-HQ-OAR-2010-0505-6953
Comment Excerpt Number: 16

Comment: EPA Must Require Operators to Document the Process Conditions at the Well Site or Compressor Station during the Leak Detection Survey.

Multiple OGI survey contractors informed Commenters of their suspicion that oil and gas companies reduce production, depressurize their systems, or otherwise alter their operations during known inspections. The leak detection survey requirements in the Proposed Rule can only be effective if the target equipment is operated under normal operating conditions during the survey. To verify representative conditions, EPA should add provisions to the Proposed Rule requiring facilities to document and report all relevant operating conditions, including but not limited to flowrates and production rates.

Response: The EPA does not require facilities to document operating conditions in rules that require leak detection programs, and we do not believe that it is necessary to be more stringent for these sources than for other sources. We do not agree with the commenter that oil and gas companies are likely to reduce production during monitoring events, as this would create a negative economic impact on their companies, especially as monitoring will occur multiple times per year.

Commenter Name: Mike Gibbons, Vice President – Production
Commenter Affiliation: CountryMark Energy Resources, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-6241
Comment Excerpt Number: 62

Comment: This new regulation also requires owners and operators to develop and maintain a corporate wide and site specific monitoring plan. We have estimated costs as we continue to understand how this regulation will impact our organization. The estimates to develop a robust system will exceed 500 man hours to solicit input, develop the written program, review with the management team, and implement the program throughout our organization. At a fully loaded cost (salary and benefit) of $60 per hour, our cost to develop this system is estimated at $30,000. We include this requirement in our comments because this could be an item that EPA will review as part of the implementation of the rule. We view the time invested in developing this type of system as part of the burden for recordkeeping and reporting as discussed on Page 368 of the regulation.

Response: The rule as finalized replaces both the corporate-wide and site-specific monitoring plans with a requirement for owners or operators to develop a monitoring plan for company-defined areas that would cover the collection of fugitive emissions components at the compressor stations or well sites located within that company-defined area. This will give companies the flexibility to group well sites that are located within close proximity, under common control within a field or district, or that are managed by a single group of personnel. We have also modified the specific content requirements of the monitoring plan. We believe that these changes will ease implementation and compliance, reducing the burden discussed by the commenter. See section VI.F.1.h and section VI.F.2.g of the preamble to the final rule for more detail regarding this issue.

Commenter Name: Jeff Addington, Manager Air Quality
Commenter Affiliation: Archrock Services, L. P. and Archrock Partners Operating LLC ((individually and collectively, ArchRock)
Document Control Number: EPA-HQ-OAR-2010-0505-6944
Comment Excerpt Number: 8

Comment: The burden associated with maintaining records and complying with reporting obligations should be placed on the owner or operator of the compressor station, not the owner or operator of the particular compressors located at that station, if different. However, because in some cases Archrock is the owner and/or operator of the compressor station and, in any case, because Archrock could be indirectly impacted by the recordkeeping and reporting requirements by its customers, Archrock takes the position that it is preferable for such records to be made available upon request rather than implementing a time consuming and costly reporting requirement.

Although service providers like Archrock may need to provide the owner or operator with information regarding the components that were leaking and/or repaired, service providers should not be burdened with reporting or maintaining federal compliance records or otherwise maintaining records for their customers. Therefore, there should not be a requirement or expectation that service providers will maintain one or more digital copies of photographs of each of its customer's compressor stations, of each survey, or every leaking component. Service providers such as Archrock should merely need to verify to their customers' satisfaction that equipment has been repaired, is operating in an appropriate fashion, and convey those details to the owner or operator in a timely fashion.

Additionally, Archrock supports EPA's clarification that a "photograph of every component that is surveyed during the monitoring survey is not required." 80 Fed. Reg. at 56,615. This clarification should be incorporated into the regulation so that the obligations in 40 C.F.R. § 60.5420a(7)(vi) mandating documentation of the location and to take one or more digital photographs of each required monitoring survey are not misinterpreted to require a photograph of each leak discovered during the survey.

Response: The collection of fugitive emission components at a well site, regardless of the owner or operator, is the affected facility and is subject to the fugitive emissions monitoring and repair program requirements specified in §60.5397a, including . The introductory text of §60.5365a states that "[y]ou are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification or reconstruction after September 18, 2015." Therefore the owner or operator is responsible for complying with the applicable standards. The commenter should be mindful, however, of the definition of "owner or operator" in §60.2 of the General Provisions which states that owner or operator means "any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part." We believe that the resolution for any leaking components identified during surveys can be managed by the operator through cooperative agreements with other potential owners at the site.

We do not believe that it is necessary to state in the regulatory text that it is not necessary to take photographs of each component surveyed during the monitoring survey, as we have made our intent known both in the preamble to the proposed rule and now in this response to comment document. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for additional information related to reporting and recordkeeping.

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 48 and 43

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 42

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 43

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 44

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 43

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 27

Comment: In addition, the monitoring and reporting requirements in the Methane NSPS are duplicative of the regulations found at Subpart W, which require gas production and processing sites and compressor stations at transmission and storage sites to annually monitor for fugitive emissions and to quantify those emissions.

Response: The EPA carefully evaluated existing programs when developing the final rule and attempted, where practicable, to limit potential conflicts with existing requirements. We realize that some of the recordkeeping and reporting requirements of subpart OOOOa are similar to those of subpart W. Where a facility already has records maintained for subpart W, the owner or operator may use those records for subpart OOOOa so long as the records meet the requirements of subpart OOOOa. We point out to the commenter that the two rules have entirely different purposes and are authorized by entirely different sections of the CAA. Subpart OOOOa is authorized under section 111 of the CAA with the intent of reducing emissions of regulated pollutants from listed source categories. Subpart W is authorized under section 114 of the CAA for the purpose of gathering information. These differences may lead to similar but distinct records being required by the two rules.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 45

Comment: Kinder Morgan has significant concerns with the Proposed NSPS OOOOa Rule as it relates to fugitive emissions leak detection requirements, recordkeeping, and reporting for well sites and compressor stations. As noted above, Kinder Morgan complies with requirements not only of Subpart W for many of these same facilities, but complies with the requirements of NSPS KKK, NSPS OOOO, or NESHAP HH at its natural gas processing plants and state LDAR requirements at some of its facilities. Having implemented these programs in the past, Kinder Morgan has unique experience and expertise with the timing of implementation, frequency of surveys, timing and potential issues associated with repair, costs, and burdens of recordkeeping and reporting, among other considerations. Based on this experience, Kinder Morgan provides the following specific comments and concerns regarding EPA's proposed requirement related to equipment leaks and monitoring of such leaks.

Response: The EPA thanks the commenter for providing input on the proposed rule.

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 7

Comment: The proposed leak monitoring and repair program would be overly burdensome, costly, and duplicative of other regulatory and voluntary commitments. In addition, significant methane reductions beyond existing programs will likely not be achieved through the implementation of this leak repair program. Most of the sources at natural gas facilities are already subject to regulatory programs (NESHAP and NSPS) and the mandatory greenhouse gas reporting program (GHGRP). Dominion's large compressor stations already conduct annual methane leak surveys under the GHGRP, which cover the primary methane emission sources. In addition, for companies such as Dominion, extensive voluntary measures to reduce methane have been in place for a number of years, including a directed inspection and maintenance (DI&M) program designed by Dominion, which has achieved significant reductions in fugitive methane emissions at compressor stations.

The leak monitoring and repair (LDAR) program under this regulation should leverage monitoring already being conducted under the GHGRP (Subpart W).

Response: We disagree that the fugitive emission program contained in this regulation will not achieve reductions of methane and VOCs at the sites covered by this rule. It is important to understand that subpart W is only a reporting program. There are no requirements for owners and operators to fix sources of fugitive emissions. We believe that the fugitive emissions at the sites covered by this rule are large enough to warrant regulations to require owners and operators to address sources of fugitive emissions. See response to DCN EPA-HQ-OAR-2010-0505-6882, Excerpt 27, regarding the issue of subpart W overlap.

Commenter Name: Mike Cantrell, Chairman
Commenter Affiliation: National Stripper Well Association (NSWA)
Document Control Number: EPA-HQ-OAR-2010-0505-6758
Comment Excerpt Number: 11

Comment: In addition, NSWA wants to raise a grave objection over the reporting and regulatory requirements of the leak detection and repair requirements of the proposal, and the ability of small producers to meet them. For small operators to meet multiple layers of regulatory requirements means significantly increased costs. In crafting a program, EPA should make every effort to ensure that the federal program works in concert with effective state programs and avoids creating duplicative requirements that drive up compliance and permitting costs.

Unfortunately, EPA's current rule as drafted fails to accomplish this. This rulemaking in many ways runs counter to successful state programs and creates wasteful, burdensome reporting requirements that will not result in reducing emissions but will carry significant costs to small operators.

The proposed reporting requirements under the rulemaking expect all companies, regardless of size or production volume to implement costly data information systems to track and monitor compliance with EPA's new regulations. These massive new data systems and reporting requirements will provide little real benefit for a small business owner who operates 24 wells and has three full-time employees; however, the costs on this small operation will be significant. The NSWA wholeheartedly disagrees with forced compliance on stripper well operators. EPA's assumptions are that America's smallest companies should be subject to the guidelines as giant multinational conglomerates, which simply isn't the case. Small operators have limited budgets and staffing, and requirements for extended record keeping and processing and submission of massive amounts of photos, documentation and imagery of well sites is an unnecessary monetary burden on small operators. Most small companies keep and maintain their own records, and they should be allowed to continue to do so, and produce them upon request.

Response: We have made revisions to the recordkeeping and reporting requirements in the final rule to help streamline the requirements and alleviate burden on the operator. We have removed the proposed requirement to provide a digital photograph in the annual report for each required monitoring survey. Instead, we are requiring owners and operators to retain a record of each monitoring survey performed with optical gas imaging by keeping one or more digital photographs or videos captured with the OGI instrument. The photograph or video must either include the latitude and longitude of the collection of fugitive emissions components imbedded within the photograph or video or must consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided that the latitude and longitude output of the GPS unit can be clearly read in the image. We believe this will alleviate the burden of submitting photographs with the annual report. Photos or videos can be stored on a hard disk, removable storage media, or on the camera itself. See also response to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 62 and DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for additional information related to reporting and recordkeeping.

Commenter Name: Stuart Spencer, Associate Director, Office of Air Quality
Commenter Affiliation: Arkansas Department of Environmental Quality (ADEQ)
Document Control Number: EPA-HQ-OAR-2010-0505-6924
Comment Excerpt Number: 7

Comment: The new record keeping requirements associated with the leak detection and repair (LDAR) are particularly burdensome to smaller operators with limited staff. For example, the preamble provides limited to no justification for requiring the date-stamped digital photograph. If EPA retains the burdensome record keeping requirements, companies should be allowed to keep the records on site or at a regional field office and produce them upon request. Companies should not be required to submit electronically or manually to the permitting agency.

Response: The date-stamped digital photograph serves as a record that someone performed a monitoring survey at the site. In the traditional LDAR scenario, the owner or operator tags all of the equipment that must be monitored, and when the Method 21 operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. This log serves as a documentation of the LDAR monitoring survey. In the fugitive emissions program under subpart OOOOa, we are not requiring owners and operators to document readings for each component, but we still need a compliance assurance mechanism to document that a monitoring survey was performed. We believe that keeping a digital photograph from the survey is a quick and easy way to fulfill this requirement.

See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for additional information related to reporting and recordkeeping.

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 13

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 15

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 14

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 14

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 14

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 13

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 16

Comment: According to EPA's analysis, "[t]he annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years." Veritas estimates that the actual annual burden imposed by these Rules will be closer to 40-60 hours per affected well site, which will result in an additional cost of $3,500-

$5,000 in labor per well site per year. Given that there are hundreds of thousands, if not more than a million, well sites around the nation, these reporting and recordkeeping requirements will eventually balloon into tremendous industry-wide compliance costs.

Response: We reviewed the recordkeeping and reporting requirements throughout the rule to assure that they are the minimum necessary to verify compliance. In response to comments that the EPA underestimated the recordkeeping and reporting burden, we revised the ICR and Supporting Statement (available in the docket) for the final rule to more thoroughly document this burden. In the end, we believe the burden imposed by the final rule is reasonable. A summary of the estimated burden is presented in section X.B of the preamble to the final rule.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 67

Comment: Secondly, the cost benefit analysis has several flaws which underestimate the cost of the data collection in reporting. OGI surveys to be performed on multiple occasions throughout the year will necessarily make this effort a full-time year-round endeavor, not a specific-scheduled event. Small producers and even large producers will need to contract with outside third-party vendors to perform the surveys and/or EPA Method 21 surveys. Availability of FLIR cameras and gas sniffers may well be an immediate problem. Most producers, large and small, will not own the equipment today. The best estimate of a camera is $85,000 to $110,000. However, the most costly item may ultimately be the data systems and/or management of change system that will be required.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 15, DCN EPA-HQ-OAR-2010-0505-6240, Excerpt 2, and DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 4.

Commenter Name: Rodney Sartor
Commenter Affiliation: Enterprise Products Partners L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6807
Comment Excerpt Number: 25

Comment: EPA should reduce the recordkeeping and reporting requirements associated with the LDAR program for compressor stations.

The proposed LDAR fugitive emission requirements include substantial reporting and recordkeeping requirements, such as creating detailed corporate plans, site-specific plans, and ongoing requirements to complete detailed reports regarding the fugitive emissions surveys. We object to these onerous recordkeeping and reporting requirements, which EPA has borrowed from requirements designed from large facilities, such as natural gas processing plants and refineries. These requirements are ill-suited for small facilities, like compressor stations, that do not have their own full-time compliance staff. Rather than simply borrowing from other programs, EPA should craft a compliance plan that is actually suited to the transportation and storage segment of the oil and gas industry, or allow operators the flexibility to craft plans suited to the nature of their businesses.

EPA has estimated the reporting and recordkeeping requirements associated with this program to be an average $3,163,699 in annualized costs. As staggering as that figure sounds, Enterprise believes that EPA has substantially underestimated the administrative burden that these requirements would place on midstream businesses. According to EPA's analysis, "[t]he annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years." This estimate fails to take into account the fact that the proposed NSPS is a highly complex and technical rule with a number of overlapping requirements. Anyone who is offering comments on these rules can tell you that digesting and processing the requirements is no easy or fast task. Operators will have to train their personnel to make sure that they full appreciate all of the requirements. Operators will also have to ensure that personnel understand how these requirements interact with other EPA air requirements, such as the GHG emissions reporting in 40 C.F.R. part 98.

In addition, operators in states with their own state methane emissions rules will need to understand and convey to personnel the differences between the two sets of requirements. For example, the Texas Railroad Commission places limits on the venting or flaring of gas, and Colorado, Wyoming, Ohio, and Pennsylvania have state regulations regarding natural gas emissions and leaks. Differentiating between the requirements from state and federal regimes—particularly when those requirements conflict or overlap—will take additional time and resources.

Given the complexity of the proposed NSPS, and the near-constant reporting and recordkeeping requirements included in the proposal, Enterprise estimates that the actual annual burden imposed by the proposed NSPS will be closer to 52.7 hours per affected compressor site, which would result in an additional cost of $1,799.18 in labor per compressor site per year. Given that there are around 5,000 compressor stations around the nation, these reporting and recordkeeping requirements will eventually balloon into significant industry-wide compliance costs.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 62, for information related to the monitoring plan. See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 15, for information related to burden. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for information related to reporting and recordkeeping.

Commenter Name: C. William Giraud
Commenter Affiliation: Concho Resources Inc.

Document Control Number: EPA-HQ-OAR-2010-0505-6847
Comment Excerpt Number: 15

Comment: We anticipate that if the Proposed Methane Standards are adopted the fugitive emissions monitoring, recordkeeping and reporting requirements alone will cost us $4,000.00 per facility annually. For 2016, Concho assumes that we will be bringing online 100 to 150 new facilities. Therefore, the cost of implementing this rule, just for fugitive emissions, will cost us $400,000.00 to $600,000.00. It is difficult to fathom how this tremendous cost expenditure, which is solely for bookkeeping purposes, will benefit the environment.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 15. The EPA disagrees that recordkeeping and reporting are solely for bookkeeping purposes. Recordkeeping and reporting requirements are vital components of compliance assurance. Compliance with the final rule is essential for reduction of emissions targeted by the final rule, which does benefit the environment. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for information related to reporting and recordkeeping.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 16

Comment: EPA proposes excessive and unnecessary recordkeeping and reporting requirements that would only burden industry and offer no environmental or other public benefit. These proposals include submission of unnecessarily detailed annual reports; corporate fugitive missions monitoring plans; site-specific monitoring plans; third-party verification requirements; mandatory audits related to fugitive emissions verifications (to be performed by third parties); and requirements that companies publish "qualitative environmental information" on their company websites. Each of these proposals is unreasonable and unnecessary.

Response: The EPA disagrees that recordkeeping and reporting offer no environmental benefit. Recordkeeping and reporting requirements are vital components of compliance assurance. Compliance with the final rule is essential for reduction of emissions targeted by the final rule, which does benefit the environment. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for information related to reporting and recordkeeping.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 119

Comment: Recordkeeping Costs Are Significantly Underestimated

The Colorado Regulation 7 record keeping requirements are not as stringent as the proposed Subpart OOOOa requirements. Based on survey data provided by 9 companies subject to Colorado Regulation 7, the average record keeping cost per basin is $188,125 with a reoccurring average annual cost of $39,444. That represents 41% of the average annual survey cost per basin.

Companies conducting voluntary LDAR surveys estimate their recording keeping costs at $60,000. Additionally companies that maintain a copy of OGI records estimate the data storage burden to be approximately 102 MB per survey per well. These costs represent approximately 26% of the average annual recurring LDAR costs per basin.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 15, for information related to costs. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for information related to reporting and recordkeeping.

Commenter Name: Urban Obie O'Brien
Commenter Affiliation: Apache Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6808
Comment Excerpt Number: 20

Comment: §60.5365i LDAR Reporting: Monitoring and reporting for all fugitive emission components, versus a summary of the well site itself, creates a significant requirements and paperwork burdens for both government agencies and industry. Having such onerous reporting requirements for tens of thousands of individual components increases potential for error within government agencies and industry. As described in Paragraph F of our General Comments, Apache estimates the rate of growth for affected facilities will be 750 new facilities each year. Considering the proposed frequency of LDAR inspection and repair verification, the reporting burden for LDAR alone will produce thousands of individual reports each year, with unlimited potential for growth into the future.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 15, for information related to costs. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for information related to reporting and recordkeeping.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 16

Comment: EPA Must Limit Duplicative and Burdensome Recordkeeping and Reporting Requirements in the Fugitive Emission Control Program

QEP appreciates EPA's solicitation of comments on ways to minimize the recordkeeping and reporting burden in NSPS OOOOa. See 80 Fed. Reg. at 56616. As proposed, QEP believes EPA's fugitive emission control program recordkeeping requirements are over burdensome. In several cases, EPA is proposing duplicative requirements. Some of the proposed requirements are also unreasonable, asking operators to record certain information that will not be informative or valuable to the Agency. QEP provides the following comments with an eye toward conserving both the Agency's and the regulated community's resources, while maintaining the environmental benefit associated with the fugitive emission control program as a whole. QEP urges EPA to provide operators with more flexibility to conduct fugitive emission control surveys in a manner that is most effective and efficient for each operator and each affected well site facility. QEP highlights the following proposed burdensome recordkeeping requirements in 80 Fed. Reg. at 56663- 56698 and provides comments on how such requirements should be revised:

- Corporate-wide monitoring plans must provide a procedure "for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained." 40 CFR § 60.5397a(c)(7)(iii). QEP has found that maximum viewing distances vary from one individual to another. Therefore, the requirement to maintain a corporate-wide maximum viewing distance under the fugitive emission control program is unreasonable and lacks the flexibility operators need to conduct effective and efficient fugitive emission surveys. QEP requests that the above requirement be removed from the NSPS OOOOa requirements.
- Each site specific monitoring plan must identify "[d]eviations from your master plan." 40 CFR §60.5397a(d)(1). QEP assumes EPA's reference to "master plan" is the required corporate-wide monitoring plan in§ 60.5397a(c). QEP submits that identifying all deviations from the corporate wide monitoring plan in each site-specific monitoring plan is burdensome for operators. Sites vary from site to site and from basin to basin. Dependent on development plans, operators could reasonably drill hundreds to thousands of wells in a basin over several years. Each well site will have hundreds to thousands of fugitive emission components. Deviations may be inevitable and pointing out all the variations would be extremely difficult, if not impossible. This requirement is also duplicative in nature because each site-specific monitoring plan will already contain adequate details of the survey for that site. Pointing out where those details conflict with the "master plan" is unnecessary. QEP requests that the above requirement be removed from NSPS OOOOa.
- Site specific monitoring plans must "include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences." 40 CFR § 60.5397a(d)(3). Operators conducting OGI surveys must respond to a number of variables out in the field. These variables include weather, adverse monitoring conditions (e .g., wind, sky condition) and interferences (e.g., steam). Also, each operator representative may want to walk through a site differently. There are too many variables at each well site for operators to commit to a specific defined walking path for each survey. QEP requests that the above requirement be removed from EPA's fugitive emission control program.
- Records for each monitoring survey must note "[a]ny deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan." 40 CFR §

60.5397a(k)(S). Building from QEP's second bullet point above, deviations are varied, many and inevitable.
Requiring operators to record every deviation from the site specific monitoring plan at every survey is extremely burdensome. QEP submits to EPA that the corporate-wide and site specific monitoring plans should act as guidance for the operators and not represent inflexible requirements that the operator must consistently identify for each survey.

Response: The EPA has removed the requirement for a corporate-wide and site specific monitoring plan in favor of an area defined monitoring plan. See responses to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 62, and sections VI.F.1.h and VI.F.2.g of the preamble to the final rule for information related to monitoring plans and DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 15, for information related to costs. See sections VI.F.1.h and VI.F.2.g of the preamble to the final rule and responses to DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, for information related to the walking path required in the monitoring plan.

We note that the elements required in the monitoring plan are necessary to judge the quality of the fugitive emissions survey, in light of the fact that the EPA does not have a standard method for use of OGI. We fully expect a trained and experienced camera operator to know when deviations from the standard monitoring plan are necessary, and we expect operators to make these deviations as needed in order to conduct effective surveys. While deviations may not impact the camera's detection ability and can actually improve the detection ability, this does not mean that deviations from the monitoring plan should not be noted. The record provides valuable information to air agency reviewers on how surveys are conducted. It allows air agencies to determine if deviations from the monitoring plan are adequate and warranted. And information on deviations from standard practices can even lead to future development of best practices procedures.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 38

Comment: Records for each monitoring survey must note "[a]ny deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan." 40 C.F.R. § 60.5397a(k)(5). Building from the Alliance's master plan statement in the above section, deviations are varied, many, and inevitable. Requiring operators to record every deviation from the site-specific monitoring plan at every survey is extremely burdensome. The Alliance submits the corporate-wide and site-specific monitoring plans should act as guidance for the operators and not represent inflexible requirements that the operator must consistently identify for each survey.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6811, Excerpt 16.

Commenter Name/Affiliation: Ben Shepperd / Permian Basin Petroleum Association
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6849 / Excerpt Number: 63

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 57

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 57

Commenter Name/Affiliation: W. Michael Scott, General Counsel / Trilogy Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6603 / Excerpt Number: 66

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 58

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 61

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 60

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 58

Commenter Name/Affiliation: Michael Hollis / Diamondback E&P LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6869 / Excerpt Number: 22c

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 8c

Commenter Name/Affiliation: Denzil R. West, Vice President / Reliance Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6915 / Excerpt Number: 22c

Commenter Name/Affiliation: Brandon M. Black, Vice President / BC Operating, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6968 / Excerpt Number: 19c

Commenter Name/Affiliation: Joe Strickling, Operations Manager / Patriot Resources, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6978 / Excerpt Number: 19c

Comment: In addition, the Rules require operators to focus time and resources on paperwork, rather than developing new solutions, by imposing continuous reporting and recordkeeping requirements.

Response: As discussed in our response to DCN EPA-HQ-OAR-2010-0505-6797, Excerpt 15, we have made several changes in the final rule to minimize the recordkeeping and reporting burden. The EPA notes that reporting is an essential element in compliance assurance, and this is especially true in this sector. Because of the large number of sites and the remoteness of sites, it is unlikely that the delegated agencies will be able to visit all sites. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for information related to reporting and recordkeeping.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 5

Comment: EPA's Component-Based LDAR System is Overly Burdensome, Subpart OOOOa envisions a regulatory design that would first require each operator to count all components at each facility. It would then require each operator to calculate a percentage of components that is determined to be leaking at each facility. That percentage of leaking components found at each site would then be used to determine the survey frequency for the corresponding site. While Noble appreciates EPA's desire to develop a comprehensive technology-based LDAR program, Noble believes that the approach proposed by EPA would be far more burdensome, less cost-effective, and no more environmentally effective than a program that used estimated facility emissions to determine the frequency of surveys for individual sites.

Colorado's fugitive emissions program is an example of how a regulatory agency can readily and relatively easily use actual uncontrolled emissions to determine the appropriate frequency of surveys. Under Colorado's program, larger facilities, which tend to have greater oil/condensate throughput and more components under pressure, would receive more frequent surveys than would facilities with lower actual uncontrolled emissions. This approach avoids the need to define the kinds of facilities that are covered. By its very nature, Colorado's program also identifies the smallest potential emitters, and requires either a one-time OGI survey, or an annual survey. This approach also is superior to the EPA proposal in that it is more likely to identify "fat-tail" emitting components in a reasonable time frame, especially if EPA elects to allow annual surveys for some facilities. Finally, while the Colorado approach does not provide for a step-up/step-down mechanism, it nonetheless offers noteworthy environmental benefits. This is the case because as production declines at a facility, actual emissions also decline along with a parallel decline in survey frequencies. Overall, Colorado's approach is simpler, more transparent, and far less burdensome than the EPA proposal; and it is achieving environmental benefits.

Under the proposed subpart OOOOa approach, every operator would have to train personnel to identify components (see the section immediately below), and then assign personnel to visit each individual site that becomes subject to the fugitive emissions program to conduct a component count (any existing site where a new well is drilled, regardless of whether it is fractured, and every existing well that is fractured or refractured). That, in itself, would be a prodigious task for a company like Noble, which has more than 3,000 facilities in the Denver-Julesburg basin alone, spread out over 400,000 net acres, about 200 facilities in Texas spread out over 50,000 net acres in the Eagle Ford basin and about 54,000 acres in the Delaware basin, and 26 facilities in West Virginia and Pennsylvania, spread out over 350,000 net acres. Noble would have to design a system for tracking every instance in which a new component is added to a site that becomes subject to the fugitive emissions program, or a component is removed from such a site as production declines. Many hundreds of employees are involved in constructing, maintaining, and operating these sites, and the potential for inadvertently changing the component count would be commensurately large.

The detailed tracking for individual components during a survey, and the tracking of components found to be leaking and then repaired would add significantly to the time needed to conduct a survey of a facility. Finally, the proposed rule does not account for the fact that some components are obstructed and cannot easily be individually surveyed, and some equipment (and components) cannot safely be surveyed with OGI technology, since it is not intrinsically safe and cannot be used in many areas where flammable vapors may be present. EPA provided no guidance on how such components would be treated in the initial count, or in subsequent surveys. Neither did EPA address the kinds of alternative survey methods that might be acceptable in such situations. States such as Colorado have provided operators with greater latitude in selecting monitoring technologies, to address situations such as this, as opposed to the unnecessarily rigid protocol proposed by EPA. Noble encourages EPA to consider those state approaches and to pursue a less prescriptive approach to conducting surveys for fugitive emissions.

Response: The EPA thanks the commenter for their detailed input regarding the burden of the proposed fugitive emissions monitoring program. In response to this and other comments, we have made changes to the fugitive emissions monitoring program in the final rule. Among other changes, we have removed the requirements for shifting performance-based monitoring frequency and replaced it with fixed-frequency monitoring. See sections VI.F.1.d and VI.F.2.c of the preamble to the final rule for more details regarding this issue.

In regards to intrinsically safe devices, we are aware of an OGI instrument that is rated for use in Class 1 & 2 in Division 1. To address commenters' concerns for other situations, we have also added new provisions for difficult-to-monitor and unsafe-to-monitor components in §60.5397a(g)(3) and (4). We note that with the use of OGI, we expect most equipment components to be accessible for monitoring.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 6

Comment: EPA Should Adopt an Emissions/Production Based Approach That Reflects State-Based Approaches. As discussed above, Noble does not believe that the regulatory approach outlined in the proposed subpart OOOOa is well suited to its intended purpose. Instead, Noble strongly encourages EPA to consider the approach taken by states such as Colorado in designing a cost-effective LDAR program. Working with industry, regulators and the public, Colorado developed a strong and effective LDAR program that uses actual emissions to establish a tiered system for the frequency of surveys for well sites and tank batteries. That approach was selected, at least in part, because larger facilities, with larger throughputs typically will have more components than will smaller facilities, and the potential for leaks will be commensurately higher.

Conversely, smaller facilities typically will have fewer components and a lower overall potential for leaks. Furthermore, a tiered system based on actual emissions will isolate the smallest facilities and provides a regulatory regimen that acknowledges their low probability of risks and provides for a one-time only survey. EPA's efforts to provide an appropriate level of surveys for the smallest oil and natural gas facilities does not have that benefit of simplicity and cost-effectiveness.

Finally, a program like Colorado's is not burdened with the unnecessary but costly task of identifying and tracking every component at every facility, yet yields equivalent environmental benefits. Noble anticipates that EPA's proposal would require the company to track both the number of components and leaking components at each of many thousand facilities, and then to track the requisite frequency of surveys for each individual facility based on the percentage of leaking components at that individual facility. That would be a logistical challenge of the highest order.

Response: The EPA did evaluate the Colorado approach to determining the frequency of conducting monitoring surveys. While the final rule now includes a fixed-frequency monitoring schedule for both well sites and compressor stations (see sections VI.F.1.d and VI.F.2.c of the preamble to the final rule for more details regarding this issue), we did not adopt Colorado's tiered approach. Although smaller facilities with fewer components may have lower emissions than larger facilities, given the large number of smaller facilities nationwide and the overall amount of GHG and VOC emissions these facilities collectively emit, we believe it is just as important to monitor these facilities as larger facilities. Therefore, for the final rule we determined that semiannual monitoring for well sites and quarterly monitoring for compressor stations was the frequency for which the cost of control is reasonable. Therefore, we incorporated these fixed monitoring schedules into the final rule.

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 9

Comment: The OGI Protocol Proposed by EPA Would be Unnecessarily Burdensome. Noble recognizes that in its 2014 White Paper on Oil and Natural Gas Sector Leaks, EPA acknowledged a lack of experience and information on the use of OGI technologies to identify leaks. EPA's draft Technical Support Documents on Optical Gas Imaging Protocol, and the Technical Support Documents Appendices on Optical Gas Imaging Protocols reiterate EPA's uncertainty about the use of OGI technologies outside the refinery and petrochemical processing plant sectors. Unfortunately, it appears EPA's ambivalence led to the creation of an OGI protocol (captured both in the requirements for a monitoring plan and in the requirements for recordkeeping and reporting) that would be far more complex and costly than those employed by states like Colorado, and which likely would provide no incremental environmental benefit to compensate for that complexity and cost burden.

For example, EPA proposes that a monitoring plan would have to include:

- A procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained, presumably for each category of components;
- A procedure for determining maximum wind speed and ensuring that monitoring occurs only at wind speeds below that threshold;
- How the operator will ensure an adequate thermal background, presumably for each component or category of component;
- The operator must have a defined walking path for each facility, which would require the development and maintenance of thousand ds of site maps.

In addition, the operator must then maintain records that show

- The ambient temperature, sky conditions, and maximum wind speeds at each survey, although EPA does not provide any information on how survey personnel would determine maximum wind speed and other conditions at a facility where meteorology could change constantly over the course of a single survey;
- Any deviations from the monitoring plan, which is itself highly prescriptive;
- Documentation of each source of fugitive emissions, without stating what "documentation" would entail; and,
- A digital photograph of each survey that is performed for each of thousands of facilities.

Noble understands EPA's desire to ensure that OGI surveys are conducted as carefully and accurately as possible. However, Noble also emphasizes that this program is not being designed for refineries, or petrochemical processing plants, which are relatively few in number, and concentrated at single sites. Instead, EPA is proposing a program for operators who are responsible for many thousands of sites, each unique, often spread out over great distances. The level of prescription in EPA's protocol would dramatically increase costs for companies compared to the equivalent kinds of programs adopted by states such as Colorado. Moreover, Noble notes that a highly prescriptive approach such as the one being proposed by EPA would make it extremely difficult for companies on the eastern plains of Colorado, North Dakota, the Piceance Basin, and elsewhere to comply given the lengthy periods of high winds and cold temperatures experienced in these regions. Noble submits that a more flexible, less prescriptive regulatory program would provide equivalent environmental benefits at lower cost.

Response: The EPA is aware that some state and local agencies allow the use of OGI monitoring without limitations on how it is used. However, we are also aware, as documented in the draft "Draft Technical Support Document – Optical Gas Imaging Protocol (40 CFR Part 60, Appendix

K)"[6], that what OGI is capable of detecting varies considerably with many different factors, including background temperature, viewing distance, compounds in the fugitive emissions and velocity of the emissions release to name a few. We believe that the requirements of the final rule ensure that OGI monitoring for fugitive emissions will be carried out effectively. Many of the elements of the monitoring plan can be variable between sites, operators and areas of the country. For example, the maximum distance at which an OGI instrument can reliably detect fugitive emissions varies with a number of factors, including weather conditions, thermal background and the sensitivity of the instrument itself. In some cases, physical barriers or safety considerations may constrain a surveyor's ability to approach some components. In addition, as OGI technology evolves, the acceptable maximum distance may change. Instead of writing into the rule prescriptive requirements for every owner and operator to follow, in the final rule, we have provided an outline of the topics that owners and operators should consider when performing an OGI survey. As such, we do not believe the requirements outlined in the final rule preclude the use of OGI in areas like Colorado and North Dakota, as we have not stated under what conditions the operator may use OGI, but have left it to the operator to determine the conditions under which it is appropriate to use OGI.

In addition to OGI monitoring, the rule as finalized allows Method 21 monitoring for surveys and resurveys after repairs. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more details regarding this issue.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 145

Comment: EPA Needs To Reduce The Recordkeeping And Reporting Burden For Leaks

The recordkeeping and reporting requirements of Colorado Regulation 7 are significant, although the requirements are far less than EPA has proposed in this rule. Furthermore, they add burden to the operator without any environmental benefit. The recordkeeping and reporting requirements NSPS OOOO should be greatly reduced. Colorado Regulation 7 only requires that the following records be maintained:

"XVII.F.8.Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

[6] DCN EPA-HQ-OAR-2010-0505-4949

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method(s) used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired;

XVII.F.8.f. The delayed repair list, including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5., an explanation stating why the component is so designated, and the plan for monitoring such component(s)."

API request that minimal records be required to reduce the cost and burden of this rule similar to what Colorado Regulation 7 requires. Further information is not needed to ensure compliance with the leak detection and repair requirements.

Also, API requests that minimal reporting of the leaks be required. Colorado Regulation 7 simply requires that the following information be reported:

"XVII.F.9. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and"

Response: In response to this and other comments, we have made changes to the fugitive emissions monitoring program in the final rule. As part of those changes, we have replaced both the corporate-wide and the site-specific monitoring plans with a company-defined area plan (see sections VI.F.1.h and VI.F.2.g of the preamble to the final rule for more details regarding this issue). Commensurate with these changes, we reviewed the recordkeeping and reporting requirements and were able to reduce those requirements accordingly. While the recordkeeping and reporting requirements are not the same as the Colorado requirements, we believe the changes we made address the majority of the commenter's concerns. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for further information related to reporting and recordkeeping.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 29

Comment: The Proposed Recordkeeping Requirements Should be Streamlined. The requirements of proposed 40 CFR § 60.5420a(c)(15)(ii) to record specific information associated with each LDAR monitoring survey are unnecessarily burdensome and include atmospheric observations (apparently due to the proposed dependence on OGI technology), monitoring plan deviation records, and digital photograph documentation as discussed elsewhere in these comments. In contrast, the LDAR recordkeeping requirements under the West Virginia and the Ohio general air quality permitting programs streamline the recordkeeping to the date, the name of the technician, and information needed to identify the leaking component.

Antero urges the USEPA to create a less prescriptive requirement by only requiring the operator to maintain records documenting that a fugitive leak was detected and that subsequent repairs were completed in a manner that is consistent with existing state air permitting programs. The recordkeeping program should include:

- Calibration log of the equipment used to perform the LDAR survey
- The identification of any component that was determined to be leaking
- The date the first attempt to repair was made
- The date the component was repaired and determined to no longer be leaking
- If the leak cannot be repaired, a delay of repair record will be developed and dates of process shutdowns will be maintained

Response: In response to this and other comments, we have made changes to the fugitive emissions monitoring program in the final rule. As part of those changes, we have replaced both the corporate-wide and the site-specific monitoring plans with a company-defined area plan (see sections VI.F.1.h and VI.F.2.g of the preamble to the final rule for more details regarding this issue). Commensurate with these changes, we reviewed the recordkeeping and reporting requirements and were able to reduce those requirements accordingly. See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for further information related to reporting and recordkeeping.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 14

Comment: WBI Energy recommends that the survey records be maintained on site and be made available upon request by the agency administering the rule. This allows the administering agency flexibility in how they want to ensure compliance with the requirements. In WBI Energy's experience with states that already require this type of monitoring at compressor stations, the administering agency requires a summary report of the surveys as opposed to records of all the survey data collected.

WBI Energy recommends that the EPA keep the record keeping and reporting requirements in the proposed rule to the data and information necessary to ensure that the requirements of the rule are being met.

As currently proposed, for the collection of fugitive emissions components at compressor stations, the EPA is requiring a large amount of data to be submitted in the annual report which could be an administrative burden for regulated entities and administering agencies. It is not practical to submit all the survey details in an annual report. In WBI Energy's experience with leak detection programs such as this, other than the general facility information required, the regulatory authority has required such information as:

- The number of facilities inspected
- The total number of inspections
- The total number of leaks identified, broken out by component type
- The total number of leaks repaired
- The number of leaks on the delayed repair list

This information allows the administering agency to determine that monitoring is being conducted and leaks are being repaired as is the intent of the rule. More detailed information would be available upon request to the administering agency as necessary. This would reduce the burden on entities reporting and administering agencies reviewing and storing data submitted.

See previous comments. As stated above, WBI Energy recommends limiting information provided in the annual report and making all monitoring information available upon request by the agency administering the rule. Requiring all the details of the monitoring survey be submitted in the annual report is burdensome to the regulated entity filing the report and the agency administering the rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.

Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 29

Comment: Reporting. The final reporting requirement should require only what is reasonable to collect and report, based on an assessment of what information is necessary to demonstrate compliance (not necessarily, what information can possibly be collected). States like Colorado, Wyoming, and Utah are well ahead of EPA in this respect, and EPA should look to these reporting programs as models. The annual report should be a summary of monitoring surveys for the reporting period and not merely a collation and submission of all the recordkeeping requirements. Considering the voluminous amount of records, this would be a very onerous, time-consuming, and excessive task. Moreover, the rule does not justify how the proposed detailed and burdensome reporting requirements provide any environmental benefit. In particular, the report need not include items specified in proposed § 60.5420a(7) for each monitoring survey; these are items that should be kept as records, available for EPA review, but not included in the annual report.

In addition, the proposed rule does not define the format of the report, making it difficult to assess how the data should be collected, stored, and reviewed for quality. MarkWest recommends that EPA keep the reporting as simple as possible.

Finally, 40 C.F.R. § 60.5420a(b)(1)(i) requires annual reports to include the address of the affected facility. Typically well sites and even compressor stations do not have physical addresses. In lieu of the address, we recommend that EPA use the latitude and longitude of the well site or compressor station for reporting purposes.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29, for information related to recordkeeping and reporting. See response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 39, for information on the format of reporting. See response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 40, for information on physical addresses.

Commenter Name: W. Michael Scott, General Counsel
Commenter Affiliation: Trilogy Operating, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6603
Comment Excerpt Number: 32

Comment: If EPA does not allow operators to use alternative methods to detect and repair leaks, Trilogy requests that EPA remove the requirement that operators keep, and make publically available, the images resulting from these surveys. This requirement places unnecessary recordkeeping burdens on operators and has no legitimate compliance purpose. Instead, these images—which EPA proposes to make publicly available—would have a prejudicial impact on the public's perception of oil and gas operations and would unfairly open up operators to litigation challenges. The methane gases are detected and made visual by these OGI cameras at levels that are not harmful to humans. However, the images of escaping fugitive gases from the videos look like frightening clouds of pollutants and create an unjustified fear of danger to human health and the environment in the public's imagination. Preserving and releasing these images will do little but create unnecessary worries and misperceptions about oil and gas operations. EPA's proposal would only assist groups interested in engaging in fear mongering to use these images to whip up opposition to oil and gas operations.

Response: We have made changes in the final rule to the proposed digital photograph requirements. We believe concerns regarding the burden of printing or transmitting digital pictures within the annual report are the result of unclear language in the proposed rule. Furthermore, after consideration, we believe we can further streamline the requirement. Since a fugitive emissions source with fugitive emissions during the reporting period is subject to other recordkeeping and reporting requirements, this provides sufficient documentation for the annual report. Therefore, we have removed the proposed requirement to provide a digital photograph in the annual report for each required monitoring survey where a leak is not detected. See sections VI.F.1.h and VI.F.2.g of the preamble to the final rule for more details regarding this issue. We also note that the final rule does not include requirements for facilities to post compliance data on a corporate website.

While we are not requiring the digital photographs to be included in the annual report, we do believe that digital photographs are still an important component of recordkeeping for the monitoring survey. See response to DCN EPA-HQ-OAR-2010-0505-6924, Excerpt 7, for more information on this issue.

Commenter Name/Affiliation: W. Michael Scott, Vice President and General Counsel / CrownQuest Operating, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6703 / Excerpt Number: 30

Commenter Name/Affiliation: Bradley C. Cross, President/Partner / Big Star Oil & Gas, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6757 / Excerpt Number: 29

Commenter Name/Affiliation: Glenn Prescott / RK Petroleum Corporation
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6788 / Excerpt Number: 30

Commenter Name/Affiliation: W. Jeffrey Sparks / Discovery Operating, Inc
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6790 / Excerpt Number: 30

Commenter Name/Affiliation: Josh W. Luig / Veritas Energy, LLC
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6797 / Excerpt Number: 31

Commenter Name/Affiliation: Rick D. Davis, Jr. / Midland Energy, Inc. and Petroplex Energy, Inc.
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6801 / Excerpt Number: 30

Commenter Name/Affiliation: Dan G. LeRoy / Legacy Reserves Operating LP
Document Control/Excerpt Number: EPA-HQ-OAR-2010-0505-6882 / Excerpt Number: 8g

Comment: If EPA does not allow operators to use alternative methods to detect and repair leaks, Crown Quest requests that EPA remove the requirement that operators keep, and make publically available, the images resulting from these surveys. This requirement places unnecessary recordkeeping burdens on operators and has no legitimate compliance purpose. Instead, these images-which EPA proposes to make publicly available-would have a prejudicial impact on the public's perception of oil and gas operations and would unfairly open up operators to litigation challenges. The methane gases are detected and made visual by these OGI cameras at levels that are not harmful to humans. However, the images of escaping fugitive gases from the videos look like frightening clouds of pollutants and create an unjustified fear of danger to human health and the environment in the public's imagination. Preserving and releasing these images will do little but create unnecessary worries and misperceptions about oil and gas operations. EPA's proposal would only assist groups interested in engaging in fear mongering to use these images to whip up opposition to oil and gas operations.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 142

Comment: The Requirement For Capturing Photo / Image Of Leaker Is Onerous And Of Limited/No Value

§60.5397a(k)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

EPA is building on their alternative compliance requirement to submit photos of REC equipment for green completions by proposing to require a photograph of each affected well site or compressor station for each monitoring survey performed per *§60.5397a(k)(6)(ii)*, which is provided above for reference. However, under the well completions portion of the rule, a photograph is offered as an alternative to the records required. However, for the OOOOa LDAR requirements it does not appear to be offered as an alternative but just additional recordkeeping.

The photo must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. It is not clear what purpose photos of the affected well site or compressor station would serve. The preamble states (80 FR 56615) that a photo of each component that is surveyed is not required, yet a single photo of the well site or compressor, which would meet the rule requirements, is not going to show all of the surveyed components, does not show that a survey was done, and will not provide any indication that a leak was repaired.

The OOOOa requirements indicate that a photograph must be taken of ‘each source of fugitive emissions” -§60.5397a(k)(6)(ii)– which is an actual leak. The proposed regulatory language and preamble appear inconsistent. A photo of a survey being conducted does not provide any additional compliance assurance that the survey requirements were met. Relying on the operator’s certification, procedure, and documentation of repairs provides the greatest amount of compliance assurance for an OGI survey.

In addition, photographs create a security risk such as terrorist activities, retaliation, and anti-competitive activities. Oil and natural gas production and gathering operations are generally un-manned and may not have security measures such as cameras, fences, or gates. The proposed photos of fugitive monitoring activities will inherently capture details that would otherwise not be available. If EPA chooses to require photographs in electronic reporting, these detailed photos will be centralized in the public domain. Individuals with no interest in fugitive monitoring activities will have interest in viewing the photographs. EPA and states will inevitably receive Freedom of Information Act (FOIA) requests for reasons unrelated to fugitive monitoring.

Finally, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate. API members estimate the data storage requirement for these photos is approximately 100 MB per well site survey. Photographs do not provide any additional environmental benefit and should not be required under Subpart OOOOa for fugitive emissions monitoring. API requests that EPA remove the requirement to take a photograph.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 24

Comment: We also request that EPA eliminate reporting provisions that would require owners and operators of compressor stations to submit "photographs" of surveys to EPA as part of their annual report. A less cumbersome and burdensome requirement would be that owners/operators could simply retain the video of each survey (with GPS data and date embedded), rather than submitting it to EPA; and if EPA wanted to verify performance of the survey, it could obtain access to the video as it would be kept in the facility's records.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 35

Comment: The proposal would require photographs of each monitoring survey, along with the latitude and longitude of the well site or compressor station. See 40 C.F.R. §§ 60.5397a(k)(6)(ii), 60.5420a(c)(15)(ii)(F). This information is voluminous, superfluous, and provides no environmental benefit to the monitoring survey. In this regard, it is sufficient for operators to record only the date and location (the latitude and longitude) of the survey. The requested photograph recordkeeping provision, in particular, would require substantial data capacity to store and organize the photographs. Once stored, the photographs would need to be annotated with pertinent information, which would be a significant time burden. Considering the lack of environmental benefit associated with this recordkeeping exercise, we strongly oppose such a requirement in the proposed rule.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 63

Comment: While proposing unnecessarily broad annual reporting requirements, EPA did not even attempt to estimate the costs associated with such a requirement, including the manpower hours, the costs related to conducting the various analyses, as well as training personnel on the systems, the costs to interpret the relevant data prior to submission, recordkeeping, and data storage requirements and associated costs. To address these concerns, Kinder Morgan proposes the following revisions to the proposed Section 60.5420a:

Proposed Revisions to § 60.5420a:

(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station, the records of each monitoring survey conducted during the year:
(i) Date of the survey.
~~(ii) Beginning and end time of the survey.~~
~~(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.~~
~~(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~
(~~v~~**ii**) Any deviations from the **site-specific** monitoring plan or a statement that there were no deviations from the monitoring plan.

(~~vi~~**iii**) Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section.
(A) Location.
~~(B) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~
(~~C~~**B**) The date of successful repair of the fugitive emissions component.
(~~**D**~~C) Type of instrument**/method** used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

Response: See responses to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32, and DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29.

Commenter Name: Alvyn A. Schopp, Chief Administration Officer and Regional Vice President and Treasurer
Commenter Affiliation: Antero Resources Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6935
Comment Excerpt Number: 28

Comment: Proposed 40 CFR § 60.5420a(c)(15)(ii)(F) contains the fugitive emissions components recordkeeping requirement to record "one or more digital photographs of each required monitoring survey being performed." Similar requirements are contained within the proposed rule for other affected facilities. Antero objects to the requirements to record and report digital photographs and urges USEPA to eliminate this requirement. Antero suggests that inspection logs with information listed at proposed 40 CFR § 60.5397a(k)(l) through (5) will accomplish the goal of this recordkeeping requirement.

If USEPA maintains the requirement to only perform LDAR monitoring with OGI equipment, the industry will typically use a FLIR model GF320 camera. Currently, the proper way to detect a leak with a GF320 or any OGI equipment is by viewing a video image of the fugitive emission and observing a change in the image over time. The requirement to document each fugitive emission with a digital photograph that would be derived from the FLIR GF320 seems unworkable due to the need for a technician to post-process the video recording of the fugitive emission to create a photograph meeting the requirements of the regulation. This may create confusion between a qualified person in the field creating logs of fugitive emission videos and a second possibly untrained person compiling the required photographs later. The photograph requirement would be particularly burdensome on small operators, provide little if any benefit to the environment, and may become an administrative nightmare for both operators and regulatory agencies. There are numerous other means to verify the completion of a survey. This proposed requirement adds significantly to the recordkeeping burdens of the industry and should be eliminated.

Response: Concerning the digital photograph requirement, see response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32. Concerning the ability to obtain a digital photograph from an OGI camera, our experience differs from that described by the commenter. Our experience indicates that either a digital photograph or a video recording is readily obtainable from typical OGI equipment. Therefore, we are not eliminating this requirement in the final rule.

Commenter Name: Jill Linn, Environmental Manager
Commenter Affiliation: WBI Energy Transmission, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6939
Comment Excerpt Number: 19

Comment: §60.5397a(k) - Record for Each Monitoring Survey

- WBI Energy recommends removing the requirement for digital photographs of fugitive emissions monitoring at compressor stations in the transmission and storage sector. Monitoring records will likely be obtained and stored at the facility itself and it is unnecessary to photo document every monitoring survey.

§60.5420a(c)(15) - Recordkeeping Requirements for Fugitive Emissions Monitoring

- See previous comment regarding §60.5397a(k).

Response: Concerning digital photograph requirements, see response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32. Concerning recordkeeping requirements, see response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29.

Commenter Name: Kevin J. Moody, General Counsel
Commenter Affiliation: Pennsylvania Independent Oil & Gas Association (PIOGA)
Document Control Number: EPA-HQ-OAR-2010-0505-6943
Comment Excerpt Number: 37

Comment: The proposed requirement to keep digital photographs of affected well sites that include the date of the photograph and the latitude longitude embedded in the file under the recordkeeping provisions of the proposed rule is an unnecessary administrative burden that provides no environmental benefit.

The requirement to keep detailed logs for each affected facility to track LDAR surveys, leaks found, and associated repairs of such leaks provides sufficient records for affected facilities to track compliance with the fugitive emissions requirements of the rule. PIOGA suggest elimination of the requirement to maintain photographic records of the affected facility.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32.

Commenter Name: Gretchen C. Kem, Sr. Policy Advisor, Environmental and Sustainable Development
Commenter Affiliation: Pioneer Natural Resources USA, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6998
Comment Excerpt Number: 18

Comment: Recordkeeping and reporting are unduly burdensome and not feasible

The new recordkeeping and reporting requirements associated with the LDAR section are arbitrary and capricious. Specifically, the digital photograph with time stamp of the survey being conducted and the site specific map with the defined walking path. The digital photograph is an undue burden and not necessary. In the 2012 Subpart OOOO rule, a digital photograph of the green completion being performed was required as well but EPA modified this provision, deleting this requirement, presumably because it proved to be unnecessary and the burden outweighed any benefit. Similarly, the walking path map is unnecessary as well creating a paperwork exercise that has no purpose. Colorado Reg. 7 does not require these requirements either. Pioneer requests that these two requirements be stricken from the final rule and that the recordkeeping and reporting requirements resemble that of Colorado Reg. 7 which have proved to be adequate and manageable for industry.

Response: Concerning the digital photograph requirements, see response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32. Concerning the walking path requirements, we are finalizing the requirements as proposed. See sections VI.F.1.h and VI.F.2.g of the preamble to the final rule and DCN EPA-HQ-OAR-2010-0505-6806, Excerpt 13, for more details regarding this issue.

Commenter Name: Cory Pomeroy, General Counsel
Commenter Affiliation: Texas Oil & Gas Association
Document Control Number: EPA-HQ-OAR-2010-0505-7058
Comment Excerpt Number: 51

Comment: For affected well sites and compressor stations subject to initial and periodic fugitive emission surveys, the proposal would require that both records and reports contain one or more digital photographs of each required monitoring survey being performed. These digital photographs must include the date taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph. EPA states that it believes that digital pictures and frame captures can help ensure that OGI for fugitive emissions is being performed properly and requests comment on the viability and benefits of this approach, as well as the areas to which it might be expanded.

The proposal would require digital photographs and logs to be available at the affected facility or the field office, and EPA solicits comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely. And, although the preamble states that a photograph of every component that is surveyed during the monitoring survey is not required, the proposed rule language appears to require digital photographs of each fugitive emissions component and each leak observed.

EPA should delete the requirement for digital photographs in any final rule issued because it will impose significant costs and, more importantly, will not provide an effective means for ensuring that fugitive emission OGI is being performed properly. Furthermore, such a requirement would add an unnecessary burden on owners and operators and provide no real environmental benefit. These photographs will not provide any additional compliance assurance that the survey requirements were met. Indeed, photographs cannot demonstrate that an appropriate survey was conducted and that proper repairs were performed. The operator's certification, relevant procedures, and repair documentation provides the suitable assurance that an OGI survey has been conducted.

Moreover, photographs of fugitive emissions monitoring activities will necessarily capture more information than would otherwise be publicly available. These images may contain confidential business information. If made available to the public, these photographs could inadvertently pose a security risk to the facility and raise concerns over vulnerability to terrorist activities, retaliation attempts, and anti-competitive activities. Oil and natural gas facilities are generally unmanned and are not protected by fences, gates or other security measures. In addition, permitting agencies will inevitably begin receiving FOIA requests for these photographs for reasons unrelated to fugitive monitoring. If EPA chooses to require that photographs be submitted as part of its electronic reporting requirement, interested members of the public can – and will – submit Freedom of Information Act requests for these photographs for reasons unrelated to fugitive emissions monitoring, making a huge amount of detailed information about these oil and gas facilities available to the general public. TXOGA therefore urges EPA to eliminate the digital photograph recordkeeping requirement in its entirety. To the extent that EPA nonetheless proceeds with requiring digital photographic records, EPA should not require such photographs or other digital images to be uploaded to permitting agencies. Even if digital photographs could be justified, which they cannot, the cost of collecting and storing such images (which would be significant) would mean that it would not survive a BSER cost analysis. We note that EPA has not provided any cost analysis on this issue.

While EPA appears to be concerned that owners or operators would claim that OGI monitoring was conducted without having actually surveyed the well site or compressor station, this concern is not supported by any evidence in the record that companies would commit what is essentially fraud. TXOGA members operate in a highly regulated environment, even those that are smaller businesses. There is no basis for EPA to assume that companies would falsify the required certifications under Section 60.5420a(b)(1)(iv). Numerous federal CAA programs require inspections, LDAR, and other work practices but do not require digital proof of monitoring. This requirement goes far beyond anything that is necessary to provide a reasonable assurance of compliance.

Finally, we note that this requirement could raise First Amendment concerns for owners and operators, as some employees or contractors possess religious beliefs that do not permit them to have their photograph taken. A categorical requirement that photographs be taken with the operator in the photograph as a form of compliance verification may violate these individuals' right to freely practice their respective religions. Companies are not permitted to discriminate on the basis of their employees' religions and cannot impose this requirement on those employees whose religions prohibit photographs. TXOGA urges EPA to rely on other, less oppressive, potentially unconstitutional, and at least controversial requirements.

Simply put, EPA should eliminate any digital photograph requirement from the final rule because it will provide no additional environmental benefit or compliance assurance and represent a substantial burden to regulated entities.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32, for more information on the digital photograph requirement. In regards to the First Amendment concerns raised by the commenter, we note that one of the options for this requirement is to take a photograph using the optical gas imaging instrument. Because the image is coming from the instrument, the instrument operator will not be in the photograph. Should the owner or operator choose to take a digital photograph of the monitoring survey being performed in lieu of capturing an image from the optical gas imaging equipment, we believe that the photograph can be framed in such a manner to capture the instrument without capturing the instrument operator. Therefore, we do not believe that we are creating an oppressive or unconstitutional situation. With regards to the cost, we have included costs for recordkeeping in the BSER analysis under the line item subsequent activities planning (See the fugitive emissions section (Chapter 4) of the TSD). The digital photographs can be stored on a computer hard drive, removable storage media or can remain in storage on the camera itself at low cost.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 13

Comment: Reporting. EPA has also proposed to require affected facilities to include one or more digital photographs of each required monitoring survey being performed. EPA requested comment on whether the digital photographs and logs should be sent directly to the permitting agency electronically. The Division is concerned about the reporting burden on both industry and the implementing authority. If EPA does not determine that Colorado's LDAR program would demonstrate compliance with the NSPS OOOOa LDAR program, then the Division suggests that

EPA specify that owners and operators retain these photographs and logs rather than submitting the records electronically to the permitting agency. The Division also suggests that EPA specify that affected facilities supply these records to the permitting agency upon request. The Division believes this will help reduce recordkeeping and reporting burdens.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32.

Commenter Name: Matthew Hite
Commenter Affiliation: Gas Processors Association (GPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6881
Comment Excerpt Number: 21

Comment: EPA's Proposed Recordkeeping Requirements Are Overly Burdensome and Should Be Reduced

EPA proposes a series of recordkeeping requirements in 40 C.F.R. § 60.5397a(k) that go far beyond what is necessary to document the results of an LDAR survey and verify their accuracy. GPA is committed to accurate recordkeeping as a means of verifying compliance with the NSPS program. However, we are concerned that many of the recordkeeping requirements proposed by EPA will serve no purpose in improving the quality of the LDAR program and thus would impose unnecessary costs on operators of compressor stations. GPA urges EPA to revise the proposed recordkeeping requirements to avoid such unnecessary obligations.

First, EPA should eliminate the requirement for survey operators to include their training and experience in the monitoring survey record. See 40 C.F.R. § 60.5397a(k)(3). The corporate-wide monitoring plan that EPA is proposing for Subpart OOOOa already includes training requirements for conducting an LDAR monitoring survey. Therefore, it is redundant and unnecessary to require operators to include their training for each individual survey. Nor is the prior experience of the operator relevant to the success of an LDAR program. Many of these operators will be trained once this rule is final but have little experience outside of any certification. Thus, documenting operators' training and experience on each survey adds an extra recordkeeping burden. GPA requests that recordkeeping under 40 C.F.R. § 60.5397a(k)(3) be limited to the operator's name and title.

Second, EPA should clarify the process for obtaining records for ambient temperature, sky conditions, and maximum wind speed at the time of the survey pursuant to 40 C.F.R. § 60.5397a(k)(4). Bringing meteorological equipment such as a wind anemometer and thermometer to the survey, in addition to an infrared camera and other equipment, is unduly burdensome. EPA should eliminate this requirement outright since historical weather data is readily available online or, alternatively, clarify that such data can be obtained from the National Oceanic and Atmospheric Administration ("NOAA") or a comparable source after the survey is complete.

Third, EPA should clarify the types of information that would satisfy the location requirement in 40 C.F.R. § 60.5397a(k)(6)(i). Specifically, GPA is unsure how, if at all, the location of a leaking component should be distinguished from other components at the same site. Does EPA require the precise latitude and longitude of the specific component, the process unit, the associated equipment, or the well or compressor site generally? It would be overly burdensome to keep such information for each leaking component. Documentation in a log should be sufficient to document that a site was monitored and is consistent with approaches that EPA has historically used for fugitive emissions monitoring in other NSPS Subparts.

Fourth, EPA should eliminate the requirement to document the instrument used to resurvey repaired fugitive emissions components pursuant to 40 C.F.R. § 60.5397a(k)(6)(iv) because such documentation is unnecessary. Instead, regardless of whether the resurvey was completed by OGI or Method 21, a "certification" from the company verifying that the resurvey showed the component was repaired should be allowed and sufficient. This "certification" could also verify that any OGI equipment used was verified prior to use. Such an approach would simplify the monitoring process while still ensuring the integrity of the monitoring program.

Fifth, EPA's proposal to require digital photographs pursuant to 40 C.F.R. § 60.5397a(k)(6)(ii) is both unnecessary and confusing. As an initial matter, the requirement to provide digital photographs is extremely burdensome and offers no benefits from a compliance standpoint over alternative options. Rather than requiring digital photographs in all cases, affected facilities should be provided with multiple options for recordkeeping. For example, logs are already required in the proposed rule that are similar to recordkeeping logs for other LDAR rules. These records include sufficient information to document the survey was completed. Photographs serve no additional purpose. Likewise, GPA urges EPA to allow operators to tag leaking components at each site instead of requiring digital photographs of the leaking components. Photographs do not provide any additional environmental benefit over alternative compliance options and should not be required under Subpart OOOOa for fugitive emissions monitoring.

Further, in the event that digital photographs are required, EPA must clarify in the final rule that such photographs are only required for fugitive emissions components that are found to be leaking. EPA states in the preamble that "[a] photograph of every component that is surveyed during the monitoring survey is not required." 80 Fed. Reg. at 56,615. However, in the rule, the requirement for digital photographs is a sub requirement to 40 C.F.R. § 60.5397a(k)(6), which addresses "Documentation of each source of fugitive emissions (e.g. fugitive emissions components)." EPA must clarify in 60 C.F.R. § 60.5397a(k)(6) that the sources of fugitive emissions that require such document are only leaking components and not all fugitive emissions components at the site.

In addition, to the extent that digital photographs are required for recordkeeping purposes, GPA urges EPA to protect them from public disclosure, either by excluding them from reporting requirements or by designating such photographs as confidential business information ("CBI") that need not be disclosed to the public. While created for the purpose of verifying fugitive emissions monitoring surveys, the digital photographs will necessarily capture details about oil and gas production and gas gathering operations that are not otherwise available the public. These photographs will be of interest to individuals and organizations that have no verifying fugitive emissions monitoring activities. For example, public disclosure of photographs can create security risks and could facilitate terrorist activities. Oil and natural gas production and gas gathering facilities are typically unmanned and in many cases do not have security measures such as fences or gates. Providing digital photographs of such facilities could provide would-be terrorists with the information needed to disrupt oil and natural gas supply chains. Likewise, making digital photographs publicly available could encourage anticompetitive activities by providing competitors with visual access to proprietary operational information. If digital photographs are included in reporting requirements, state and federal agencies will inevitably begin receiving Freedom of Information Act ("FOIA") requests for these photographs for reasons unrelated to fugitive monitoring. Thus, if EPA chooses to require photographs in electronic reporting, it must first develop a process to protect those photographs from public disclosure to protect the physical and competitive interests of the owners and operators.

Sixth, EPA "solicit[s] comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely." Under these circumstances, it is sufficient that these records be kept at the operator's facility or field office and provided to EPA or other permitting agencies upon request. Adding additional recordkeeping burdens on these agencies would needlessly extend the amount of resources necessary to maintain and review these records. Additionally, many state agencies do not have existing systems to receive this data electronically. Keeping the records at the operator's facilities and available to agencies upon request will reduce the burden on regulatory agencies while ensuring that the records will remain available as needed.

Response: Concerning recordkeeping requirements, see response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29. Concerning digital photograph requirements, see response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32. The EPA agrees that it did not intend owners and operators to take a photograph of each component, only the components that had fugitive emissions or one photograph of the survey being performed in the case where no component is found to have fugitive emissions. We have reworded the final rule to make this clearer. We have also finalized an option to allow owners and operators to tag components with fugitive emissions that cannot be repaired during the initial monitoring survey instead of taking a photograph of these components.

In the final rule, we are not requiring electronic submittal of data directly to the permitting agency, although we are requiring electronic submittal of certain reports to the Central Data Exchange (CDX). See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146, for additional information related to reporting and recordkeeping.

We are not specifying training criteria for those personnel surveying or repairing sources of fugitive emissions due to the variety of OGI and Method 21 instruments that are available and the variety of components and equipment configurations that exist in the field. We believe that each owner or operator should determine and implement the training that is appropriate for their specific situation and document this decision in the monitoring plan. Likewise, we believe it is important for the owner or operator to document that the personnel performing each survey has met the necessary qualifications specified in the monitoring plan.

We are not limiting the methods by which the owner or operator documents the ambient temperature, sky conditions and maximum wind speed at the time of the survey. While NOAA or comparable sources may document this data, it may not correlate precisely with the conditions that exist at individual well sites and compressor stations, and we believe that it is important for owners or operators to document the conditions that occurred at the site. The owner or operator should document how they intend to determine this information in the monitoring plan. We do note that portable thermometers and anemometers are inexpensive and readily available, and determination of sky conditions are readily achieved through visible observation. We also note that EPA requires this data for other documentation, such as Method 9 and Method 22 readings.

We are not limiting what satisfies documenting the location of each component found to have fugitive emissions. We are leaving this to the discretion of the owner or operator, but note that it is incumbent upon the owner or operator to document this in such a manner that it is possible for another person to determine which component was the source of fugitive emissions.

We are not eliminating the requirement to document the instrument used to resurvey a repaired fugitive emissions component. We believe that this information is integral to understanding how the resurvey was performed, and we do not believe that this it is burdensome to note this information alongside the information of when the resurvey was performed.

Finally, we note that we are not declaring any information CBI, but this does not preclude a source from making such a claim. Any data claimed to CBI should not be uploaded electronically to the CDX.

Commenter Name: Don Anderson, Director of Environmental
Commenter Affiliation: MarkWest Energy Partners, L.P.
Document Control Number: EPA-HQ-OAR-2010-0505-6957
Comment Excerpt Number: 28

Comment: Recordkeeping. Proposed § 60.5420a(c)(15)(i) requires a fugitive emissions monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emission components at a compressor station, as required in § 60.5397a(a). As discussed in our comments under Fugitive Emissions Monitoring Plan, there is no need for a site-specific plan; a corporate monitoring plan will suffice.

The proposal (40 C.F.R. § 60.5397a(k)(6)(ii) and § 60.5420a(c)(15)(ii)(F)) would require photographs of each monitoring survey, along with the latitude and longitude of the well site or compressor station. This information is voluminous, superfluous, and provides no environmental benefit to the monitoring survey. In this regard, it is sufficient for operators to record only the date and location (the latitude and longitude) of the survey. The requested photograph recordkeeping provision, in particular, would require substantial data capacity to store and organize the photographs. Once stored, the photographs would need to be annotated with pertinent information, which would be a significant time burden. Considering the lack of environmental benefit associated with this recordkeeping exercise, we strongly oppose such a requirement in the proposed rule.

Response: Concerning digital photograph requirements, see response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32. Concerning the corporate-wide and site-specific monitoring plans, see response to DCN EPA-HQ-OAR-2010-0505-6241, Excerpt 62.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 140

Comment: The Rule Should Not Require A Separate Report For Each Well Site

API interprets "each collection of fugitive emissions components" in §60.5397a(l) (provided below for reference) to refer to a single LDAR survey at a well site or compressor station. The requirement to provide a separate report for each well site, even where the report can combine multiple emission surveys at a well site, is onerous. API requests the option to combine reports for multiple wells sites or compressor stations and submit the combined reports in one annual report.

§60.5397a(l) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions at a compressor station may be included in a single annual report.

Response: In the final rule, all of the reporting requirements for fugitive emissions have been moved to §60.5420a. §60.5420a(b) states that if you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the required information.

Commenter Name: Thure Cannon, President
Commenter Affiliation: Texas Pipeline Association (TPA)
Document Control Number: EPA-HQ-OAR-2010-0505-6927
Comment Excerpt Number: 22

Comment: EPA proposes to require documentation of each source of fugitive emissions, including *inter alia* photographs of each required monitoring survey being performed. The photographs would have to include "the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file." TPA requests that EPA clarify that it is only asking for latitude/longitude data for the overall site being surveyed, as opposed to separate global positioning system ("GPS") coordinates for each fugitive emissions component being surveyed or repaired. The point would be to demonstrate that the survey was performed, and where it was performed; there would be no need for more granular data such as GPS coordinates at each separate piece of equipment being surveyed.

Response: The EPA agrees with the commenter. See response to DCN EPA-HQ-OAR-2010-0505-5290, Excerpt 5, for more information on this issue.

Commenter Name: Terry L. O'Clair, Director, Division of Air Quality
Commenter Affiliation: North Dakota Department of Health
Document Control Number: EPA-HQ-OAR-2010-0505-6928
Comment Excerpt Number: 3

Comment: The timeframes are too short for the large number of sources. There are an extensive number of sources/components that will be regulated and they are spread out over a large geographic area. The sheer volume of monitoring, recordkeeping, and reporting for these sources will be difficult. Further, the reporting requirements may unnecessarily create a burdensome process where the regulatory agency may be flooded with paperwork.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 62

Comment: As described in detail below in the proposed specific rule revisions, annual reports should not be duplicative of other requirements and should include only information necessary to demonstrate compliance with applicable requirements. All other information is superfluous, does not inform compliance with the relevant requirements, and would be overly burdensome. For example, EPA proposes that operators provide photographs with latitude and longitude displayed and included in the digital files. First, a plain photograph cannot demonstrate the presence or absence of a leak, so such photographs are neither necessary nor reasonable to request. Second, photograph files are typically large in size and require significant memory, cellular data, and computer space to transmit from a laptop at a facility to a server and to store them. Additionally, OGI cameras do not have the functionality to record latitude and longitude, and furthermore, a requirement to record latitude and longitude for each component at a facility is totally unnecessary since the latitude and longitude will basically be the same for each component at a given facility. Furthermore, the requirements to document every start/stop time are unreasonable, and without providing useful information. Kinder Morgan agrees that the operator's name and the survey dates surveys could be included in the log; operator training records could be maintained on-site. Kinder Morgan objects to including the operator's name in the reports and other public documents. And finally, certain requirements would be duplicative of an operator's site-specific plan, and should be excluded from the annual report. The remainder of the proposed reporting data elements: current monitoring frequency, the number and types of components found to have fugitive emissions, the date of first attempt to repair, the date of final repair, any source of fugitive emissions found to be technically infeasible or unsafe to repair, etc. should be maintained by the operator on site.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29 for information on recordkeeping and reporting. Concerning digital photograph requirements, see response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32. We disagree with the commenter that OGI cameras cannot record latitude and longitude. Certain OGI cameras have the functionality to embed the latitude and longitude data within the file. Additionally, owners and operators are only required to take one photograph per monitoring survey. One photograph generally does not require a lot of file space or memory to store or transmit. Likewise, we do not believe that it is unreasonable to document the start and stop times of surveys, as this provides a complete picture of the survey, and it only takes a few seconds to document this information. Finally, we note that while the monitoring plan contains certain data, the information in the records and annual report is meant to document that the owner or operator followed the monitoring plan and the results of the survey.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 167

Comment: The recordkeeping requirements, however, are unduly burdensome and not workable.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 43, 56, 57

Comment: EPA requested comment on "ways to minimize recordkeeping and reporting burden." The proposed record keeping requirements associated with the LDAR are particularly burdensome. Should EPA retain the burdensome record keeping requirements, companies should be allowed to keep the records on site or at a regional field office and produce them upon request. Companies should not be required to submit electronically or manually to the permitting agency.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29. In the final rule, we are not requiring electronic submittal of data directly to the permitting agency, although we are requiring electronic submittal of certain reports to the Central Data Exchange (CDX).

Commenter Name: James Martin
Commenter Affiliation: Noble Energy
Document Control Number: EPA-HQ-OAR-2010-0505-6852
Comment Excerpt Number: 15

Comment:

- EPA proposes that the operator compile and report for the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station, the records of each monitoring survey conducted during the year:
  - The submittal of all these data points for each survey conducted during the year will be very cumbersome and even challenging to assemble in a format that would be meaningful to the EPA or state. While Noble understands the need for information and data, maintaining the records and having them available upon request would be far less onerous and would serve the same purpose. As an example, for 2015 (through October), Noble has conducted 7944 IR camera inspections (as required by Colorado regulatory frequencies) and has identified more than 13,000 leaks. A layout of a report that could be envisioned in this scenario could include more than 24,000 lines (extrapolated for 12 months) including a line for each survey and each leak. That does not account for the requirement to submit photographic evidence, which when printed, would be over 9,500 sheets of paper (extrapolated to 12 months, 1 sheet of paper per photo).
- EPA also proposes that the operator report ambient temperature, sky conditions, and maximum wind speed at the time of each survey as well as any deviations from the monitoring plan or a statement that there were no deviations.
  - See previous responses to the monitoring plan. As noted earlier, maximum wind speed will be difficult to monitor and report, particularly in the many areas of oil and gas exploration and production where high wind speeds are often recorded over long periods of time.
- Finally, EPA proposed that the operator document each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section; the location; and provide one or more digital photographs of each required monitoring survey being performed.
  - Noble has outlined above its concerns with these requirements individually. Noble's concerns are magnified by the cumulative complexity and burden of the monitoring, recordkeeping, and reporting requirements of the fugitive emissions

> program. Noble respectfully submits that EPA's proposed program would require significant time and resources to implement, and provides few or no environmental benefits beyond those provided by a streamlined approach adopted by the state of Colorado.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6935, Excerpt 29, for information regarding reporting and recordkeeping. We note that the reporting format for the annual report is set by the electronic form that owners and operators will use in the CDX. See response to DCN EPA-HQ-OAR-2010-0505-6603, Excerpt 32, concerning requirements for digital photographs. Regarding the comment on wind speeds, we believe that determining and documenting wind speed during monitoring surveys is necessary to ensure that valid results are obtained and will not be overly burdensome to the owner or operator.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 143

Comment: API Strongly Opposes Sending Digital Photographs And Logs To Permitting Agencies

EPA is seeking comment on page 56615 of the preamble "on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely; and how to minimize recordkeeping and reporting burdens." API strongly opposes sending digital photographs and logs to the permitting agencies. EPA's cost estimate did not account for the burden of data storage requirements and management of data that would be place on the states. There is no apparent benefit to requiring the state to manage and maintain copies of this information. And, as indicated previously, there are real security risks when putting photographs in the public domain that includes geo data for exact location of sites that are unmanned with limited security.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6944, Excerpt 9, for information regarding site locations. In the final rule, we are not requiring electronic submittal of data directly to the permitting agency, although we are requiring electronic submittal of certain reports to the CDX.

Commenter Name: Emily E. Krafjack
Commenter Affiliation: Connection for Oil, Gas and Environment in the Northern Tier, Inc., (C.O.G.E.N.T)
Document Control Number: EPA-HQ-OAR-2010-0505-6787
Comment Excerpt Number: 26

Comment: Noting that the proposed rule includes new requirements for monitoring and repairing sources of fugitive emissions at well sites and compressor stations and that the requirements include digital photographs along with specific corresponding documentation along with the keeping of a facility log; we recommend that these records also should be sent directly to the permitting agency electronically to facilitate review remotely. However, the electronic files should in no way be a substitute for the regulator's onsite visits and follow-up.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6884, Excerpt 146. In the final rule, we are not requiring electronic submittal of data directly to the permitting agency, although we are requiring electronic submittal of certain reports to the CDX, including the annual report. We understand that electronic reports are not a substitute for visits by the delegated air agencies, but electronic reports are an important tool that can allow agencies to review and analyze data quickly.

4.12 Emission Reductions

Commenter Name: Deborah Burney-Sigman, President, Board of Directors
Commenter Affiliation: Breathe Utah
Document Control Number: EPA-HQ-OAR-2010-0505-6246
Comment Excerpt Number: 3

Comment: Optical gas imaging is a newer technology that is used to identify leaks so repairs can be initiated. Quarterly surveys can cut emissions by 80 percent, while semi-annual monitoring surveys and repairs can reduce emissions by 60 percent. Since Jonah Energy (WY) began using OGI as part of its emission reduction program, the company has reduced fugitive emissions by 75 percent. In the last five years, it reduced repair time by 85 percent, cut labor, and cut its gas losses significantly. Emissions have fallen, from 351 tons to a mere 31. Based on a cumulative effect, Jonah Energy's cost savings have exceeded $5 million to date, which more than pays for all repairs and labor – to include covering the cost of the cameras and camera operators.

The final federal rule should require operators to perform at least semi-annual Leak Detection and Repair (LDAR) surveys with OGI cameras on all permitted oil & gas sites. There is abundant evidence that this is would be cost effective. EPA should initiate programs to fund and train state and tribal compliance teams in the use of OGI IR cameras, so as to enable compliance teams to conduct their own surveys, and to assist small operators in compliance.

Response: The EPA agrees with the commenter that OGI technology is a valuable tool for identifying components with fugitive emissions and reducing fugitive emissions, and accordingly has finalized requirements for its use to identify fugitive emissions at well sites and compressor stations, although Method 21 may be used an alternative. Method 21 is a standard EPA method with a long history of use in detecting fugitive emissions, and the reductions achieved through the use of Method 21 monitoring will be equal to the reductions achieved with OGI. See sections VI.F.1.c and VI.F.2.b of the preamble to the final rule for more information regarding the use of Method 21.

Regarding the comment on the frequency of monitoring, the final rule requires semi-annual monitoring at well sites and quarterly monitoring at compressor stations. See section VI.F.1.a and section VI.F.2.a of the preamble to the final rule for more information regarding this issue.

We are aware that many state and local air agencies already own and are using OGI instruments on a regular basis. Additionally, commercial training classes and web-based training materials are available for regulators and operators seeking assistance with use of OGI technology.

Commenter Name: Wesley D. Lloyd, Freeman Mills PC
Commenter Affiliation: Texas Independent Producers and Royalty Owners Association (TIPRO)

EPA-HQ-2018-001886 3/2/2018 ED_001544_00002162-00738

Document Control Number: EPA-HQ-OAR-2010-0505-6893
Comment Excerpt Number: 13

Comment: Impractical to Quantify Methane "Saved"

The innate characteristics of fugitive emissions makes it impractical and costly to quantify the amount "saved." In fact, recognizing the futility and lack of tangible benefit, the most aggressive state LDAR programs already in existence do not attempt to require quantification of the amount saved. The quantity of components at a facility subject to monitoring likely reach into the thousands or tens of thousands. Therefore, quantifying the amount of fugitive emissions saved at each component would be cost prohibitive.

Response: The EPA is not requiring owners and operators to quantify the emissions reductions for individual components in the final rule.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 10

Comment: The rule also relies on fugitive emission factors from AP-42 to estimate methane and VOC fugitive emissions from a typical oil and natural gas and oil well facility, respectively (4.5 tons per year (tpy) methane and 1.3 tpy VOC from oil and natural gas; 1.1 tpy methane and 0.3 tpy VOC from oil well facility). 80 Fed. Reg. at 56,635. The AP-42 emissions factors are taken from a 1995 EPA protocol. The outdated protocol is based on 24 facilities and a sample size totaling 368 components, with the majority of the 24 facilities being "uncontrolled," *i.e.*, no LDAR program. The use of AP-42 emission factors, aside from being 20 years old and not accounting for improvements in component quality and other equipment, vastly over-report and over-estimate the typical level of fugitives at an oil and natural gas facility. Inaccuracies in this respect are further compounded by the fact that this proposed rule applies only to new and modified sources that use state of the art components and equipment, and are designed to minimize leaks. The end result is an overly conservative and inaccurate estimation of fugitive emissions; skewing the purported benefits from the rule and affecting EPA's determination on cost-effectiveness.

In addition, EPA appears to adopt estimates made by the state of Colorado in the run up to the 2014 rulemaking with respect to VOC/methane reductions anticipated from the proposed Colorado LDAR program. 80 Fed. Reg. at 56,635. (citing the Air Pollution Control Division Initial and Final Environmental Impact Analysis). EPA selected 80 percent VOC/methane emission reduction, to be expected from a quarterly frequency, 60 percent reductions from a semiannual frequency, and 40 percent reductions from an annual frequency). The Colorado estimations, however, were fraught with error and do not represent conditions actually experienced. Moreover, EPA skews Colorado's data points without support or explanation. For example, the Colorado EIA estimates 60 percent reduction for quarterly monitoring frequency whereas EPA assumes 60 percent reduction for a semiannual monitoring frequency, and the Colorado EIA estimates 80 percent reduction for monthly monitoring frequency whereas EPA assumes 80 percent reduction for a quarterly monitoring frequency.

Colorado's estimates, which were based on inflated and inaccurate fugitive emission estimations and factors to begin with, assumed that LDAR benefits both increase with the frequency of inspection and remain constant over time. Neither of these assumptions is true. First, Colorado's estimates were based on EPA guidance that applied a "rule of thumb" assessment and did not actually conclude that benefits from an LDAR program increase with frequency or stay consistent over time. Second, the EPA guidance relied upon addressed fugitive emission reductions at chemical plants and petroleum refineries (not smaller, scattered oil and gas facilities), utilized outdated data, and employed simple averages as opposed to a more accurate distribution of components that would be expected at smaller oil and gas facilities. *See also* 80 Fed. Reg. at 56,635 (EPA citing to a 1996 report to estimate fugitive emissions component counts). These and other errors combined to result in inaccurate estimates about the cost-effectiveness of the Colorado LDAR program and the ostensible benefits of increased frequency in particular.

Contrary to the conclusions drawn in the Colorado rulemaking which EPA is apparently relying on to justify this rule, actual experience with the LDAR program *at upstream oil and natural gas facilities* demonstrates: (1) that following the implementation of an LDAR program, leak rate frequency found upon initial monitoring drops significantly during subsequent monitoring to less than 1 percent; and (2) that providing operators the flexibility to focus on high emitting and likely-to-emit components delivers the most cost-effective benefits. Experience also demonstrates that these low, post-initial monitoring leak rates generally are sustainable over the long term. *See Colorado Regulation 7/Litigation Support*, prepared for WPX Energy, Inc. by Trihydro Corporation, at 1-1 (January 6, 2015).

Response: The EPA continues to believe that it has reasonably estimated emissions from leaking components at well sites and compressor stations based on the available information.

For the proposed rule, the EPA used the best information available to estimate uncontrolled fugitive emissions from well sites and compressor stations. Prior to finalizing the rule, we updated the equipment counts for well sites based on the latest available data from the Greenhouse Gas Reporting Program, but no other new information for quantifying uncontrolled fugitive emission rates became available. Accordingly, we continued to use the emissions factors found in the AP-42 for the final rule analyses, in the absence of improved emissions factors.

See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17 for the response to the potential emission reductions used for the final rule.

The EPA acknowledges that the highest rate of leaking components is likely to be detected during the initial monitoring, with the percentage of leaking components subsequently leveling off at a lower rate. However, the control efficiencies estimated for the analyses represent the later, steady-state conditions and do not reflect the large initial reductions, which would be achieved regardless of the frequency of subsequent monitoring.

See response to DCN EPA-HQ-OAR-2010-0505-6787; Excerpt 35, response to DCN EPA-HQ-OAR-2010-0505-6884; Excerpt 122, and Chapter 4.3.3.2 of the Technical Support Document for the final rule for more information on this issue.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 44.2

Comment: EPA relied on a Colorado Air Quality Control Commission ("CAQCC") report prepared in support of its recently revised Regulation Number 7 to estimate fugitive emissions reductions as a function of LDAR monitoring frequency. The CAQCC Economic Impact Analysis ("EIA") estimated the following reductions for LDAR frequencies: 40% reduction for annual monitoring of well production tank batteries; 60% reduction for quarterly monitoring; and 80% reduction for monthly monitoring. In reaching this conclusion, the CAQCC relied on certain EPA guidance documents; however, these 40/60/80 percent reduction assumptions are not actually stated in EPA's guidance documents. The potential reductions discussed in the EPA guidance documents cited by the CAQCC discuss *general* values from chemical plants and petroleum refineries (not oil and gas facilities—or any sector of the oil and gas industry), which relied on outdated information and data (in some cases dating back to 1980), and provided simple averages that do not reflect actual distribution of components (e.g., the average is not properly weighted)—and thus, provide no actual data demonstrating that monitoring frequencies of less than one year are necessary, effective, or environmentally beneficial. Thus, Kinder Morgan questions the reliability of the underlying sources the CAQCC relied upon to reach its assumptions—and thus, the sources EPA relied upon in support of this Proposed NSPS OOOOa Rule. This is further evidenced by the fact that when EPA published its set of five technical white papers as recently as April 2014, EPA concluded that available studies (which inherently includes the EPA Best Practices Guide and EPA Leak Protocol) "did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program." Thus, as a threshold matter, the CAQCC's assumptions are questionable.

Even if the CAQCC's assumptions are supported by appropriate data, EPA unilaterally skews the CAQCC's data points without support or explanation. For example, the CAQCC EIA estimates 60% reduction for <u>quarterly</u> monitoring frequency whereas EPA assumes 60% reduction for a <u>semiannual</u> monitoring frequency, and the CAQCC EIA estimates 80% reduction for <u>monthly</u> monitoring frequency whereas EPA assumes 80% reduction for a <u>quarterly</u> monitoring frequency. Without the adequate data or supporting rationale, these conclusions are not defensible.

Additionally, and perhaps more importantly, existing data exists to demonstrate that LDAR emissions benefits diminish in subsequent years. While Kinder Morgan does not agree that the EPA Leak Protocol supports the CAQCC's EIA estimates of 40/60/80 percent reductions, Kinder Morgan agrees with the EPA Leak Protocol's underlying premise that "the three most important factors in determining the control effectiveness are (1) how a 'leak' is defined, (2) the initial leak frequency before the LDAR program is implemented, and (3) the final leak frequency after the LDAR program is implemented." Applying these factors, and in Kinder Morgan's experience, the majority of leaks are found and fixed at the outset. Then, typically during successive surveys, fewer leaks are found and the number of detected leaks does not increase again for over a period of at least a year. In fact, based on a case study of application of NSPS OOOO to a Kinder Morgan facility from the period of October 2012 to December 2014, with quarterly monitoring events, Kinder Morgan tracked the total number of leaks detected each quarter. As expected, the number of leaks identified was highest at the first monitoring event; however, after that first monitoring event, the number of leaks identified drastically declined for nearly a two-year period. The data indicate that the number of detected leaks decreases significantly after the first inspection (and repair) and stabilize (if not continue to decrease) for a period not less than a year; thus, supporting Kinder Morgan's position that annual monitoring is more than adequate to reduce emissions in a cost-effective manner.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 10.

The EPA disagrees that annual monitoring is adequate to reduce emissions in a cost-effective manner. We also do not agree that the results of the cited study indicate that annual monitoring is adequate. During the study, the commenter conducted quarterly monitoring and presumably fixed leaks as they were found. Because the leaks drastically declined over the course of the two-year period, we believe this demonstrates that a quarterly monitoring program drastically reduces leaks. This does not demonstrate what the results would have been if the leaks were monitored annually.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 17

Comment: Recent studies have demonstrated that following an initial inspection, subsequent LDAR surveys offer diminishing returns in terms of leak reductions. Take, for example, a member company's recent analysis. This Alliance member analyzed emission reduction levels associated with different fugitive emission control survey frequencies on operations in Wyoming. The member concluded annual fugitive emission control monitoring results reduces emissions by 52 percent—a level of reduction higher than the 40 percent EPA estimated. The member company also concluded semiannual monitoring results in a 57 percent reduction in emissions; this is similar to the 60 percent reduction estimated by the proposed rule. Finally, the study concluded quarterly monitoring only provides a 61 percent reduction in emissions; this is significantly lower than the 80 percent reduction estimated by the proposed rule. Ultimately, the member company's analysis shows increased inspection frequencies does not result in the emissions reductions as contemplated by the proposed rule. Put another way, the emission reduction potential of each LDAR inspection decreases drastically when the frequency of the inspections is increased.

Additional studies, referenced by the American Petroleum Institute (API) in its comments on the proposed rule (and discussed in more detail above in Section II(b) above) demonstrate that the most important factor in a successful LDAR program is the initial inspection. A semi-annual or quarterly inspection schedule offers little in the way of added environmental benefit, but substantially increases program cost. A third-party survey indicates a voluntary LDAR program still exhibits a leak rate of less than 1 percent, even in fields without a current regulatory LDAR program. These studies suggest the proposal's estimated leak rate is overestimated.

Response: See response to DCN EPA-HQ-OAR-2010-0505-6983, Excerpt 17.

Additionally, the commenter did not provide the referenced study conducted in Wyoming, so we are unable to determine the accuracy of that data.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 223

Comment: Studies in Texas have shown that methane emissions are much higher than the EPA has estimated. One by Touche Howard in the journal, Energy, Science & Engineering, has claimed that work by the University of Texas and published in the proceedings of the National Academy of Sciences has greatly underestimated the amount of methane that is being emitted due to the use of a Bacharach meter high-flow sampler, which in previous studies had been shown to exhibit sensor failure leading to underreporting of natural gas emissions.

Other studies in the Barnett Shale field have found far greater emissions of methane than estimated by EPA. While we hope that the EPA estimates are correct, we encourage the EPA to be aware of these other studies.

Response: The EPA agrees with the commenter that fugitive emissions from the oil and natural gas sector are significant. We continue to believe that we have reasonably estimated emissions from leaking components at well sites and compressor stations based on the information available to us. We believe the provisions in the final rule that require the identification and repair of components with fugitive emissions at well sites and compressor stations will significantly reduce these fugitive emissions.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None

Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 234

Comment: I have this article from James Osborn that says, "methane emissions from natural gas operations in North Texas' Barnett Shale are 50 percent higher than estimates by the federal government would indicate," according to a series of studies published by -- published Tuesday in the scientific journal, Environmental Science & Technology, the finding brings into greater question the validity of Environmental Protection Agency data showing methane emissions are declining even as natural gas production in the United States boomed with the advent of hydraulic fracturing.

The study, which was commissioned by the Environmental Defense Fund and drew scientists from universities across the country, shows that the majority of methane emissions in the Barnett come from a relatively small number of sites probably through a flare of gas and other actions not accounted for in the federal data. Between one and two percent of the natural gas produced in the Barnett ends up leaking into the atmosphere, a finding consistent with similar studies conducted in gas production regions of Colorado and Utah, said Ramon Alvarez, lead senior scientist with the Environmental Defense Fund.

Response: See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 223.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 186

Comment: For these indisputable reasons, we strongly support EPA's proposed standards that will for the first time create national requirements to reduce dangerous methane pollution and waste from the oil and gas industry. However, the facts justify EPA going further than its current proposal in its effort to cut methane emission.

While inventory data provided by the oil and gas industry itself indicates it is the largest industrial source of methane in the U.S., the most recent scientific studies suggest the amount may yet be substantially higher; in fact, the most up-to-date study on methane emissions from Barnett Shale area in Texas concludes that emissions from the oil and gas sector are actually 50 percent higher than estimates.

Why the discrepancy? Scientists from EDF and Reading University researchers found that the underreporting of methane pollution was due, in large part, to a small number of sites with extremely large leaks. These so-called super-emitter sites are unpredictable. They may be old or new wells, marginal or large producers, and they may have been fine yesterday but today show evidence of large methane leaks that just cropped up.

Response: The EPA thanks the commenter for the information. See response to DCN EPA-HQ-OAR-2010-0505-7336, Excerpt 223.

Commenter Name: Mike Smith
Commenter Affiliation: QEP Resources, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6811
Comment Excerpt Number: 17

Comment: EPA Must Base the Fugitive Emissions Control Requirements on More Accurate and Data-Based Estimates

Component Counts per Hour Estimate

EPA accepts the white paper study estimates that OGI technology can monitor 1,875-2,100 components per hour. 80 Fed. Reg. 56593, 56634. QEP submits that this estimate is only applicable to large production facilities in more condensed fields. QEP estimates that surveying 1,875-2,100 components with OGI at smaller facilities (one to two wells per site) in a less condensed area of development will take an operator four hours. QEP assumes an average of 500 components per smaller facility and that each survey would take about an hour to complete (estimate does not include the time it takes to repair and resurvey any detected leaks).

Percentage of Emission Reduction Estimates by Survey Frequency

QEP welcomes the opportunity to comment on the appropriateness of the percentage of emission reductions that can be reasonably expected to be achieved with annual, semiannual and quarterly monitoring program frequencies. See 80 Fed. Reg. at 56635. EPA selected 40% as the emission reduction level that can reasonably be expected to be achieved with an annual monitoring program. Id. EPA assigned an emission reduction of 60% to semiannual monitoring survey and repair frequency and 80% to quarterly frequency. Id. QEP disagrees with EPA's expectations and submits that EPA's expected emission reduction levels for annual, semiannual and quarterly survey frequencies are inaccurate.

QEP recently conducted an analysis of emission reduction levels for fugitive emission control survey frequencies on its operations in the UGRB of Wyoming from November 2009 to November 2013. QEP concluded that annual fugitive emission control monitoring results in a 52% emission reduction level-a level of reduction higher than the 40% EPA estimated. QEP also concluded that semiannual monitoring results in a 57% reduction in emissions- similar to the 60% EPA estimated. Finally, we concluded that quarterly monitoring only provides a 61% reduction in emissions. QEP's analysis of emission reductions from quarterly monitoring is significantly lower than EPA's estimated 80% reduction.

Ultimately, QEP's analysis shows that with increased inspection frequencies, equivalent reductions in emissions are not realized. Put another way, the emission reduction potential of each LDAR inspection decreases drastically when the frequency of the inspections is increased. With diminishing returns, frequent fugitive emission inspections (i.e. quarterly and, in some cases, semiannually) are unreasonable and uneconomical. QEP welcomes the opportunity to further discuss the discrepancies between EPA estimates and QEP's UGRB analysis.

With specific regard to the fugitive emission control program in the CTG, QEP reiterates its concerns and submits to EPA the more accurate emission reduction estimates above. See EPA's CTG for the Oil and Natural Gas Industry (Draft), Section 9.3.1.1 (Fugitive Emission Detection and Correction with Optical Gas Imaging) (pgs. 9-17; 9-18).

Response: Regarding the monitoring capability of OGI technology, the EPA continues to believe that it has reasonably estimated this capability based on the information available to it. We note that our BSER analysis is based on model plants developed to represent the average facility sizes found in the oil and natural gas sector. Accordingly, we believe that we have properly considered variations among the facilities in the sector.

Regarding the control efficiencies achievable with monitoring and repair programs, see response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 10.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 157
Comment: *Overstatement of Methane Composition for Oil Well Sites*

EPA assumed that the methane composition for fugitive leaks from oil well sites was equivalent to gas well sites at 82.9 percent methane by volume. This methane content is relatively representative of the gas composition at gas well sites, but considerably higher than is present at oil well sites. In contrast, EPA assumed a methane composition of 46.7 percent by volume in their analysis of oil well completion emissions and costs. However, EPA elected not to use this composition in their analysis to evaluate the reasonableness of the costs of a program to reduce fugitive emissions from oil wells. If EPA had used the more appropriate value, the lower methane content would result in lower methane emissions and lower methane emissions reductions.

Response: Please reference the gas composition memorandum (EPA-HQ-OAR-2010-0505-0084) for the specifics on the analysis of gas composition in the oil and natural gas sector. This analysis was based on a robust data set of gas composition from various aspects of the production and transmission and storage segments. Please note that the 82.9 and 46.7 values are the percentage of methane by volume. For completions, the gas being released from the well head includes gases (i.e., methane, VOC and others) and water vapor. This gaseous mixture then passes through a separator which removes much of the water vapor (and typically entrained VOC) which reduces the total "volume" of the gas itself. Therefore, post separation the methane content of the remaining gaseous mixture is 82.9 percent. The 82.9 percent value for methane determined in the gas composition analysis is reasonable and considered to be the best available for the oil and natural gas sector. We assumed that the fugitive emissions from oil wells occurs after the separator, and therefore the fugitive emissions that occur from oil well equipment has a methane percentage of 82.9 percent. We add that it is not surprising that composition might differ between completion and the equipment components downstream when the processing of the gas has begun because of the process equipment through which it is directed.

Commenter Name: Howard J Feldman
Commenter Affiliation: American Petroleum Institute
Document Control Number: EPA-HQ-OAR-2010-0505-6884
Comment Excerpt Number: 160

Comment: *Overestimate of Gathering and Boosting Station Component Counts*

EPA's approach for estimating the model plant gathering and boosting station component counts overstates baseline emissions and emission reductions. EPA rounded up the average number of compressors per compressor station in estimating component counts for the model plant baseline emissions. Further, they also used an inconsistent approach for projecting the number of affected gathering and boosting stations in 2020 and 2025. The assumptions EPA used for estimating baseline emissions for the gathering and boosting station model plant and for projecting the number of affected new facilities include:

- 5.0 compressors per station used for model gathering and boosting station component counts. This is based on rounding up the estimated 4.5 compressors per gathering and boosting station;
- 4.5 compressors per station assumption used to project number of new facilities for 2020 and 2025.

The impact of rounding up the number of compressors per gathering and boosting station from 4.5 to 5.0 is a 10 percent overstatement of the component counts, which translates into 10 percent overstatement of baseline emissions and emission reductions. Note that this overstatement was conservatively not corrected in the revised benefit cost analysis figures.

Response: The model plant was developed to reflect the type of equipment that would be found at a typical gathering and boosting station. A typical gathering and boosting station would not have fractional equipment, but would consist of whole pieces of equipment. Therefore, we believe it is appropriate to round the equipment for determining model plants.

For the purposes of estimating the number of new facilities in 2020 and 2025, we believe that using the 4.5 compressors per station is appropriate.

4.13 Other

Commenter Name: Pamela F. Faggert, Chief Environmental Officer and Vice President-Corporate Compliance
Commenter Affiliation: Dominion Resources Services, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6946
Comment Excerpt Number: 12

Comment: Dominion seeks concurrence from EPA that the requirements of the proposed regulation are applicable only to storage compressor stations and not to storage wells and associated equipment...

The requirements of leak monitoring and repair apply to compressor stations when additional compression is added to the station; we provided comments on this applicability earlier in the document. Irrespective of the applicability criteria, we seek clarification from EPA regarding what constitutes a storage facility. It is our understanding that the leak monitoring and repair requirements only apply to the storage compressor station if the station is considered new or modified. A number of Dominion's compressor stations are located on underground natural gas storage fields. One of Dominion East Ohio's storage fields covers many square miles, and has thousands of injection and withdrawal wellheads considered part of the facility under the GHGRP. We seek concurrence from EPA that storage injection and withdrawal wellheads are not an affected source under the proposed rule. Dominion suggests clarifying the definition of affected wellhead as specific to the "Production" segment, thus exempting storage pool wellheads.

Response: See response to comment EPA-HQ-OAR-2010-0505-7058, Excerpt: 28.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 2:40 PM; Public Hearing #2 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 2

Comment: To let you know how I think the EPA can strengthen this rule, so please tighten the time frame allowed to correct methane leaks. Six months is a long time, and a great amount of methane could leak into the atmosphere in that time frame. So by shortening the time frame that you give oil and gas producers to fix leaks when it could be something that would be really simple to fix or maybe it does require more time and effort, it's worth it. Right?

Response: The EPA requires monitoring surveys to be performed at regular intervals. This does not mean that equipment is allowed to have fugitive emissions for the entire period of time between surveys. Repairs must be made within 30 days of identifying fugitive emissions. The equipment must be surveyed within 30 days of the repair to ensure the equipment is repaired and that fugitive emissions no longer exists. We believe that this timeframe for repair is necessary because some sources of fugitive emissions may take multiple attempts to repair or require additional equipment that is not readily available and may take time to obtain. Because many sites are located in remote areas, these sites are unlikely to have warehouse and maintenance shops with spare parts and tools nearby. We believe this timeframe for resurvey is necessary because the fugitive emissions survey is generally performed by contractors, and as such, the owner or operator needs time to schedule the resurvey with the contractor.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 36

Comment: Finally, 40 C.F.R. § 60.5420a(c)(15)(ii)(F) has a typographic error when referring to the number of subsequent paragraphs. As written, it states: "Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(1) through (2) of this section." There are four paragraphs under § 60.5420a(c)(15)(ii)(F), not two. If the proposed rule intends for all four paragraphs to apply, it should be revised accordingly.

Response: The EPA agrees with the commenter. We note that there have been changes to this section since the proposal, but we have corrected the reference to ensure that all subparagraphs are encompassed.

Commenter Name: Kathleen M. Sgamma, Vice President, Government and Public Affairs
Commenter Affiliation: Western Energy Alliance
Document Control Number: EPA-HQ-OAR-2010-0505-6930
Comment Excerpt Number: 42

Comment: Also, please note proposed 40 C.F.R. § 60.5397a(c) has a typographic error; as written, it states:

> Your corporate-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

However, there is no paragraph (8) under § 60.5397a(c).

Response: The EPA thanks you for your comment. We have checked the reference in the final rule.

Commenter Name: Richard S. Anderson, Director of Air Quality Compliance
Commenter Affiliation: Plains All American Pipeline, LP
Document Control Number: EPA-HQ-OAR-2010-0505-6996
Comment Excerpt Number: 11

Comment: Typographical Error. Paragraph 60.5397a(c) makes reference to "paragraphs (c)(1) through (8) of this section."

However, there is no paragraph (c)(8) in §60.5397a.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6930, Excerpt 42.

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 5

Comment: Digital images Latitude/Longitude stamp (page 431) - We want it noted that the camera's commonly used record the coordinates of the camera, not the equipment being imaged. We suggest the documentation section (60.5397a(k)(6)(ii)) be revised to note GPS coordinates reflect the position of the camera operator while making images.

Response: The EPA notes that the coordinates embedded or included in the photograph must note the latitude and longitude for the collection of components, not the individual components. We understand that the optical gas imaging instruments embed the latitude and longitude of the instrument, not the component being surveyed. To clarify our intent, we have added to the recordkeeping section to indicate that for each fugitive emissions component that is not repaired during the initial survey, the owner or operator must either temporarily tag the component or take a digital photograph or video that clearly identifies the location of the component (e.g., by using site landmarks).

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 8

Comment: Provided the intent is to set initial verification detection limit at 60 g/hr., we suggest 60.5397a(c) (7) (B) be reworded to the following:

"Your optical gas imaging equipment must be capable of imaging methane or propane with a resulting mixture in air equal to or less than 10,000 ppmv or a metered release into air of less than or equal to 60g/hr."

Response: We agree with the commenter about the intent and have made the appropriate changes to the final rule.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 16

Comment: It is important for EPA to include a provision for components that are difficult, unsafe, or inaccessible to monitor. This concept has been defined by states, such as Colorado in Regulation No.7. For example, Colorado does not require such components to be monitored until feasible and other conditions are met. The following are the relevant provisions from Regulation No. 7:

Regulation No. 7, XVII.F.5.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

Regulation No. 7, XVII.F.5.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

Regulation No. 7, XVII.F.5.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

Solution: Anadarko recommends that EPA incorporate a provision for components that are difficult, unsafe or inaccessible to monitor for purposes of safety of our personnel. We recommend EPA consider using Colorado Regulation No. 7 language in any final regulation.

Response: The EPA has added provisions for difficult-to-monitor and unsafe-to-monitor components in §60.5397a(g)(3) and (4) to address these concerns. We do not believe that there is a need to add provisions for inaccessible-to-monitor equipment. We do not believe that any of the fugitive emissions components in this sector will be buried or insulated, and we have received no data to the contrary. Additionally, while we understand that some components at large chemical plants and refineries may be obstructed by equipment or piping due to the number of components and tight piping configurations, we do not believe those same concerns exist in this sector. We note that with the use of OGI, equipment components should generally be accessible for monitoring.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 29, 45

Comment: The PBPA requests clarification as to the distance an OGI camera operator is expected to be from potentially leaking components. Many operators' facilities are within bermed areas for compliance with spill prevention control and countermeasure reasons, and as a matter of safe operating procedures, field personnel are not allowed to enter these bermed areas except at metal fabricated stairways. Additionally, to reduce trip-and-fall hazards associated with berms and pipping laid across the ground, field personnel are not allowed to step over piping or berms except during repairs. If EPA requires that the OGI camera operator enter these areas, hazard exposure will increase considerably. As an alternative, the PBPA suggests that EPA allow OGI observations be made from distances that do not require entry into bermed areas or where pipping step-overs are required.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6880, Excerpt 9.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 35 and 49

Comment: The requirement that an operator rent, purchase or contract persons to use an OGI is very expensive and burdensome. Currently only two manufacturers' mass produce OGI cameras and only one of those cameras is intrinsically safe. The PBPA would request clarification that the proposed rule suggest that operators enter possibly explosive environments with non-intrinsically safe electronic devices.

Response: The EPA is not requiring owners and operators to operate in an unsafe manner. We note that the final rule adds Method 21 as a monitoring option for fugitive emissions. In addition, we have added unsafe-to-monitor provisions to the final rule.

Commenter Name: Gary Buchler
Commenter Affiliation: Kinder Morgan, Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6857
Comment Excerpt Number: 23

Comment: The transmission and storage sector of the natural gas industry proves very complex and in most circumstances is heavily regulated by the U.S. Department of Energy through the Federal Energy Regulatory Commission ("FERC"), and the U.S. Department of Transportation through PHMSA, particularly for safety purposes. PHMSA has established programs requiring operators to implement fixed gas detection and alarm systems in each compressor building and to develop procedures for leak surveillance and repair. For example, under 49 C.F.R. Section 192.613, PHMSA requires that each operator "have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions." It is important that the safety programs dictated by PHMSA regulations are considered when adding additional leak detection regulations by way of the Proposed NSPS OOOOa Rule.

Response: See the response to DCN EPA-HQ-OAR-2010-0505-6872, Excerpt 20.

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 6

Comment: Verification testing (page 424). It appears the agency has set a requirement for the Monitoring Plan to require a test for initial verification as well as for daily verification. It is not clear if the daily verification check has a regulatory minimum concentration or flow rate any different than for the initial verification. We are assuming that the Monitoring Plan will set a flow rate or concentration for the daily check under environmental conditions at the site that is equal to the initial verification limit of 60 g/hr.

Response: The monitoring plan will set the appropriate daily verification check to ensure the instrument is working as intended and the underlying data quality of those observations made during the day would be equivalent to those made during the initial verification. The monitoring plan should also include information from an initial verification to set the proper operation envelope for the specific OGI instrument(s).

Commenter Name: Wes Crawford, President
Commenter Affiliation: Infrared Services & Thermal Imaging of Texas, LLC
Document Control Number: EPA-HQ-OAR-2010-0505-5290
Comment Excerpt Number: 7

Comment: Verification Gas Mixtures-We suggest the verification gases be a single gas, propane or methane. We believe the agency should not force the use of special and expensive mixtures of verification gases that will be released to the atmosphere. We currently use propane as a verification gas at most locations. We also suggest clarification that the concentration is based on the resultant mixture in the atmosphere and not the verification gas. Finally we suggest that detection be based on either a concentration in air or a metered flow rate into the atmosphere.

Provided the intent is to set initial verification detection limit at 60 g/hr., we suggest 60.5397a(c)(7) (B) be reworded to the following:

"Your optical gas imaging equipment must be capable of imaging methane or propane with a resulting mixture in air equal to or less than 10,000 ppmv or a metered release into air of less than or equal to 60g/hr."

Response: We are not requiring a specific gas, concentration or rate nor have we have specified that a gas must be released for daily verification. The requirement is for initial demonstration of the system and the performance of the operating envelope used in the monitoring plan. There may be appropriate alternatives to gas releases for daily checks such as optically transparent closed gas cells. We expect the monitoring plan will set the appropriate daily verification check to ensure the instrument is working as intended and the underlying data quality of those observations made during the day would be equivalent to those made during the initial verification.

We agree with the commenter about the intent of 60.5397a(c)(7)(B) and have made the appropriate changes to the final rule.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 8

Comment: The Division also requests EPA clarify the intent and extent of the OGI daily verification check. The Division has found the daily verification check to be an area of confusion for using OGI as an alternative work practice in NSPS KKK monitoring, specifically whether it is equivalent to a calibration requirement. In contrast, the Division conducts a specific non-uniformity compensation ("NUC") check on the FLIR camera to ensure the equipment is operating properly. The Division also employs a standard operating procedure for Division IR camera inspections.

Response: The non-uniformity compensation ("NUC") is not a verification of the proper operation of the equipment. The NUC is more akin to a zero calibration of a concentration point monitor. It is used as a single point to adjust the offsets of the pixel array. It is a critical piece of any OGI monitoring plan, but may not be used for daily verification. The daily verification check is meant to ensure the instrument is working as intended and the underlying data quality of those observations made during the day would be equivalent to those made during the initial verification.

Commenter Name: Laredo Petroleum
Commenter Affiliation: Laredo Petroleum

Document Control Number: EPA-HQ-OAR-2010-0505-6474
Comment Excerpt Number: 5

Comment: If a leaking component is repaired during the survey, as proposed on page 56595, column 3, under Fugitive emissions from well sites and compressor stations, and not leaking at the end of the day of the inspection, is that considered a leaking component?

Response: Any component found to have fugitive emissions during the monitoring survey is considered to be a component with fugitive emissions, regardless of when the component is repaired.

Commenter Name: Ben Shepperd
Commenter Affiliation: Permian Basin Petroleum Association
Document Control Number: EPA-HQ-OAR-2010-0505-6849
Comment Excerpt Number: 55, 41, 42

Comment: Confirmation should be provided that leaks discovered as part of the LDAR program will not be required to be quantitated against permitting limits, and confirmation that no discovered leaks will compel an operator to file emission event reporting.

Response: The requirements for permitting programs are independent of the requirements for fugitive emissions monitoring program under the NSPS. Different delegated air agencies may have different requirements on how leaks are handled in regards to comparison with permit limits. The operator should confirm with the permitting authority how leaks discovered under the NSPS program are to be treated under permit and event reporting requirements.

Commenter Name: Maria Pica Karp, Vice President and General Manager, Chevron Government Affairs
Commenter Affiliation: Chevron U.S.A. Inc.
Document Control Number: EPA-HQ-OAR-2010-0505-6929
Comment Excerpt Number: 12

Comment: Definition of a leak: There are places on a well pad that are designed to release pressure for safety purposes or for tank gauging (for example, thief hatches). Typically programs in states, in recognition of this fact, do not consider emissions from properly operating devices as leaks. We understand the agency would like to limit emissions from malfunctioning devices, and Chevron is aligned and want to fix malfunctioning devices. We ask the agency to reconsider listing functioning devices as leaks and consider instead listing malfunctioning only.

Response: The EPA agrees that emissions from functioning devices, when operating as intended for normal operation and properly maintained, should not be considered fugitive emissions. We have revised the definition of fugitive emissions component to clarify that "Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission". We note that pressure relief devices and thief hatches on controlled tanks are included in the definition of fugitive emissions component, as a release from these devices are not considered normal operation.

Commenter Name: Greg Amimon, Director
Commenter Affiliation: Environmental Northern Natural Gas, Berkshire Hathaway Energy Pipeline Group (BHE)
Document Control Number: EPA-HQ-OAR-2010-0505-6933
Comment Excerpt Number: 4

Comment: Application of the definition of "reconstruction" of a compressor station?

Under proposed § 60.5430a, *"Compressor station site* means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations." Per 40 CFR § 60.15(b) reconstruction is defined as "the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility." The EPA should provide clarity that replacement of 50% of the fixed capital cost of the entire compressor station is required to constitute reconstruction, not 50% of the cost of an individual unit or component.

Response: With respect to the reconstruction of the affected facility, the commenter is correct.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 168

Comment: And the definition of "fugitive emissions components" needs fixing.

Thank you for the opportunity to comment, and we look forward to working constructively with the Agency prior to final rule promulgation.

Response: The EPA has revised the fugitive emissions component definition to address issues raised by commenters.

Commenter Name: William C. Allison
Commenter Affiliation: Colorado Department of Public Health and Environment
Document Control Number: EPA-HQ-OAR-2010-0505-6876
Comment Excerpt Number: 4

Comment: Custody transfer-EPA proposed to define the crude oil and gas source category, for crude oil production, to include the well and extend to the point of custody transfer to the crude oil transmission pipeline. The Division has found that there may be a number of "custody transfers" after processing/storage and before pipeline/transportation or refinery, thus retaining ambiguity in the requirements. Therefore, the Division requests that EPA further clarify that the point of custody transfer for crude oil production is the first point after production or storage.

Response: The rule specifically states "point of custody transfer to the crude oil transmission pipeline" means that the producer no longer retains custody of the product and it is in the custody of the transmission pipeline operator. We do not believe that we need to specify the first point of custody transfer after production or storage. See also Chapter 1 of this document for additional information.

Commenter Name: Mark A. Litwin
Commenter Affiliation: Paiute Pipeline Company
Document Control Number: EPA-HQ-OAR-2010-0505-6814
Comment Excerpt Number: 5

Comment: Paiute also supports AGA's recommendation that the addition of a compressor at an existing station should only trigger fugitive emissions NSPS requirements for that new compressor if the addition meets the legal definition of "modification," including a resulting emission increase. Further, for upgrades to an existing compressor, fugitive emissions requirements should only apply to the affected compressor if the change meets "modification" criteria.

Response: The EPA has revised the definition of modification for the collection of fugitive emissions components at compressor stations. This definition is contained in §60.5365a(j).

For further information on this topic, see section VI.F.2.h of the preamble to the final rule.

Commenter Name: Henri Azibert, Technical Director and Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: Fluid Sealing Association (FSA) and None
Document Control Number: EPA-HQ-OAR-2010-0505-6754 and EPA-HQ-OAR-2010-0505-

7338
Comment Excerpt Number: 12, 119

Comment: FSA members do recognize that there are pieces of equipment that are very specialized and may not be able to meet the general guidelines. Although this is not discussed in any detail in the proposed regulation, the FSA would like to point out that large emitters of fugitive emissions are not necessarily due to the equipment design, technology, or end of life. The problem often resides in improper installation or misapplication of the sealing products. Monitoring, maintaining, and repairing equipment properly requires highly trained engineers and maintenance personnel. Sealing technology is a very specialized field, and not part of general technical education. As the experienced workers retire, new generations of recruits need to be instructed in how to specify, use, and implement effective sealing technology. Without rigorous training programs, the result can be a significant lack of knowledge of how to properly apply readily available technology. The FSA and other organizations provides generic training material and information. So the FSA simply wishes to be considered as a technical resource. And we want to thank you for your consideration.

Response: The EPA thanks the commenter for their comment. We believe that the monitoring and repair requirements in the final rule will cover the situations described in the comment.

Commenter Name: Stuart A. Clark and Ursula Nelson, Co-President
Commenter Affiliation: National Association of Clean Air Agencies (NACAA)
Document Control Number: EPA-HQ-OAR-2010-0505-6932
Comment Excerpt Number: 5

Comment: *Methane Detection Requirements for Dry Gas Areas*

EPA notes in the preamble that, for many covered sources already subject to the 2012 VOC NSPS, no additional methane controls are required. While this approach is sound in "wet gas" areas where both VOC and methane are present in fugitive emissions, "dry gas" areas pose a different challenge. Leak detection and compliance procedures that rely solely on VOCs as a proxy for methane may not detect leaks in "dry gas" areas where fugitive methane emissions can occur without VOCs. NACAA recommends that EPA review its analysis of the leakage detection requirements to ensure that the methane emission reduction goals of the NSPS are achieved in "dry gas" areas.

Response: The EPA continues to believe that areas that are predominantly dry gas producers will typically not have the ancillary equipment that are the source of most of the fugitive emissions as outlined in the rule. Therefore, well sites containing only one or more wellheads are exempt from the fugitive emissions requirements for well sites.

We also note that the fugitive emissions detection methods outlined in this rule are not specific to methane or VOCs. The optical gas imaging technology allowed in this rule will image any compounds that have peaks in the spectral range of the instrument. The cameras that are currently available commercially do not speciate between methane and VOCs. Likewise, Method 21 provides an overall response to all compounds that the instrument can monitor. Therefore, if fugitive emissions monitoring is required at a site, the instruments will detect both methane and VOCs.

Commenter Name: David McBride
Commenter Affiliation: Anadarko Petroleum Corporation
Document Control Number: EPA-HQ-OAR-2010-0505-6806
Comment Excerpt Number: 4

Comment: In the alternative, we strongly recommend that EPA reconsider finalizing this rule and instead form a technical advisory committee including industry and state experts to develop a more effective regulation. Anadarko has a history of successfully collaborating with regulators, non-governmental organizations ("NGOs") and many other stakeholders to achieve constructive solutions on a number of issues including emissions. These solutions have been protective of public health and the environment, and continue to enable our industry to operate in a manner that produces essential energy resources, supports jobs and economic development, and generates government tax revenue.

Response: The EPA thanks the commenter for their comment. We have worked with stakeholders in refinement and implementation of the standards throughout the development of the final rule. We believe that the requirements of the rule are justified and are including requirements for fugitive emissions monitoring in the final rule.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:00 AM - 7:55 PM; Public Hearing #1 - Denver, Colorado
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7337
Comment Excerpt Number: 173

Comment: For decades the oil and gas industry has been self-reporting their leakage. They understand it's not in their best interest to self-report no more than 3 percent leakage. Yet when independent investigators go out with mobile or airborne sampling equipment, they find the leakage range from 6 to 17 percent in certain fields. The EPA must get directly involved in monitoring methane emissions.

Response: The EPA is directly involved in oversight of the compliance requirements in the final rule. We note that many of our rules are delegated to state and local air agencies, as well. Compliance oversight can include activities such as monitoring fugitive emissions from a site. Additionally, compliance oversight involves ensuring that owners and operators perform their compliance obligations in the manner specified in the regulations.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:05 AM - 8:00 PM; Public Hearing #1 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 67

Comment: There seems to be an additional problem with respect to actually measuring methane leaks. According to an article in the Pittsburgh Post-Gazette just yesterday morning, more than a dozen studies measuring emissions from shale gas sites have come up with varying conclusions about leak rates.

The article continues, "Accurate regionally comprehensive and continuous monitoring of the actual rate of leakage from shale gas production is required both to document the greenhouse gas impact of gas production and evaluate efforts to reduce emissions." Consequently, strong regulations to reduce emissions are essential, but a clear, accurate system of measuring is imperative.

Response: The EPA thanks the commenter for the information. We agree that regulations to reduce methane and VOC emissions are essential and are finalizing requirements we have determined to be reasonable for the oil and natural gas industry.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Tuesday, September 29, 2015; 9:00 AM - 11:55 AM; Public Hearing #2 - Pittsburgh, Pennsylvania
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7338
Comment Excerpt Number: 64

Comment: Hi. My name is Joy Sabl. Back in 2012, I started to hear quite a bit from people that they had gone to well sites and they could smell the gas coming off in a huge level with their noses, but the people working there had gone nose blind because they went acclimated, and the readings about the people working there, they'd show the readings and say, "Oh, there's nothing here. See the machine says so." So I have spent $30,000 of my own money to buy a reconditioned FLIR infrared camera which could show that there was gas coming off. And that was in March of 2013. In March of 2015, two years later, unrelated to my donation, a paper was published showing that the gold standard tester that is used throughout the oil and gas industry and, especially on fracking sites -- it's called a background high flow tester. It has two sensors in it, one that records in the zero to seven range and one that records up to ten times that level.

And that if the machine were not correctly calibrated daily or even more than once daily, the high-level sensor would not cut in and would instead get a zero reading. So what that means is that we have been flying blind as far as what's coming off existing oil and gas wells and pipelines. The manufacturer actually says it only needs to be calibrated monthly. This is simply not so.

Next, besides the health risk for the people around the well sites, the long-term health risks for the people who are breathing that every day -- and remember they can't smell it. They have habituated -- there's also -- once you think you're at zero and you're actually at 70, you know what you're in? You're surrounded by an explosive soup. This is an immediate danger, not only should the EPA regulate, the EPA should go back and reassess what has already escaped, should require dual sensing and testing because camera monitors would have given the lie to the other monitors and caught the flaw more than, you know, four, five, six years after the thing had been in use, and we probably would have avoided some of the explosive accidents we have had. That's a supposition, but I think it's a founded one, and we would know what we are doing to the environment, and as well as for the people working here and the people surrounding.

Thank you very much for your attention to this specific issue, in addition, to all of the other things that other people have said here that I also support. Thank you so much.

In response to request for clarification on dual sensing, the commenter state that: Oh, yes. So have you heard the example used, a Geiger counter? So I work in labs, and we use a Geiger counter quite often. So you'll have a dial, and if you think you have a low level of radiation, you set it to the low sensing button, and it'll go bleep, bleep, bleep, bleep, bleep. Okay. Once it gets to the top end, it's just maxed out. You can see that it's maxed out, and you know you have to switch the gain to the next level. This is not quite the same; it's using different sensors, but the point is it doesn't have a dial that shows you that you're off scale on the low sensor, and, therefore, need to go to the high sensor. This is something that the machine is supposed to do automatically. The report came out in March of this year. It's been covered in the New York Times as well as other sources. You can find this information quite easily. I just want full attention to be given to it because people are saying, "We don't know how often this has actually happened." And the answer is "Yes, it has, and yes, it does." And please pay attention to it because there may be a reason why you seem to be way off the scale, globally speaking. Oh, the other thing is, the guess is that the -- a significant -- a very large percentage of the methane entering the atmosphere is doing it from a small subset of the leaks. In other words, there are a lot of little leaks, but then there's some real gushers. And, actually, it's the gushers that we have been missing and there's probably more in the middle that we didn't even notice, either because the high-flow meter only the low -- I mean, sometimes you know it's calibrated right, the high sensor will work, but other times it simply won't, okay?

Response: The EPA thanks the commenter for the information. We believe that monitoring methane and VOC fugitive emissions are an important attribute of this regulation in order to effect reductions in emissions. We have evaluated the monitoring requirements and we believe we have outlined appropriate monitoring, measurement and calibration protocols to address these concerns.

Commenter Name: Public Hearing Comments On Proposed Climate, Air Quality, and Permitting Rules for the Oil and Natural Gas Industry; Wednesday, September 23, 2015; 9:10 AM - 8:00 PM; Public Hearing #1 - Dallas, Texas
Commenter Affiliation: None
Document Control Number: EPA-HQ-OAR-2010-0505-7336
Comment Excerpt Number: 29

Comment: At Jonah Energy, their original goal was to have the camera operator perform some of the leak repairs while on site. Their initial goal was 70 percent of the leaks. They're finding that they're able to make 90 percent of those repairs during the course of their inspection, and that's increasing the efficiency of their team.

Response: The EPA thanks the commenter for the information.